HIGH-RESOLUTION CHARACTERIZATION OF RESERVOIR HETEROGENEITY AND CONNECTIVITY IN CLASTIC ENVIRONMENTS

A Thesis

by

THOMAS FREDERICK HULL

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2010

Major Subject: Geology

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Approved by:

Co-Chairs of Committee,	Yuefeng Sun
	Thomas E. Yancey
Committee Member,	Walter B. Ayers
Head of Department,	Andreas Kronenberg

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ABSTRACT

High-resolution Characterization of Reservoir Heterogeneity and Connectivity in Clastic Environments. (August 2010)

Thomas Frederick Hull, B.S., Cornell University

Co-Chairs of Advisory Committee: Dr. Yuefeng Sun
Dr. Thomas Yancy

This study developed new concepts and interpretative methods for mapping reservoir heterogeneity and connectivity of a fault controlled Wilcox clastic reservoir in Texas, USA. The application of high-resolution seismic enhancement in this study allows for better delineation of subsurface geologic features, detailed mapping of reservoir heterogeneities and more accurate identification of depositional, structural, and stratigraphic characteristics that control reservoir connectivity and fluid flow.

Seismic enhancement in this study pertains to amplitude preserving neural network implementation of the Volterra integral equation of the first kind from a plane-wave solution of poro-viscoelasticity (Sun, et al., 2003). This enhancement amounts to an advanced spiked deconvolution of post-stack seismic data that broadened the dominant seismic frequency from 16Hz for the conventional seismic to 65Hz for the enhanced seismic. Bed resolution is improved from 175ft to 45ft and fault offset resolution is improved from 80ft to 20ft. High-resolution seismic interpretation was validated through synthetic seismograms, stratigraphic surface comparisons, and most

importantly using a comprehensive model-based knowledge of regional tectonics and depositional environments.

Stratigraphic features that were not resolvable in conventional seismic data can now be interpreted using the enhanced seismic data. An Upper Wilcox reservoir was identified as a transgressive sheet sand overlaying a progradational deltaic seismic facies. An Upper Middle Wilcox reservoir was identified as a probable lobate gravity flow, and a Middle Wilcox reservoir was identified as a transgressive sheet sand with over and underlying progradational deltaic seismic facies.

Geobody extraction from seismic inversion volumes delineates reservoir compartments and flow units. Reservoir connectivity analysis performed on the Middle Wilcox reservoir determined the probable drainage area for a producing well by comparing estimates of compartmentalized hydrocarbon volumes with production information. The methodology developed could help extract connected geobodies defined by sand, porosity, permeability, and hydrocarbon indicators, to map in detail the internal structure of produced reservoir and to locate new development prospects. Enhanced seismic may thus enable us to find bypassed hydrocarbons and to provide better methods for improving recovery in the studied and other mature fields.

ACKNOWLEDGEMENTS

I would like to thank my committee co-chairs, Dr. Sun and Dr. Yancey, as well as my committee member, Dr. Ayers, for their guidance and support throughout the course of this research.

Thanks also go to my friends and colleagues and the department faculty and staff for making my time at Texas A&M University a great experience. I also want to extend my gratitude to Devon Energy for providing field data and financial support. Additional thanks to Superhighres Research for the seismic enhancement and TGS Geological Products and Services for the regional well data. I am also grateful to Schumberger for the use of their Petrel software for this study.

Finally, thanks to my mother and father for their continual encouragement and to my brother for his advice. Thanks again for all of your help along the way.

TABLE OF CONTENTS

LIST OF FIGURES

FIGURE Page

CHAPTER I

INTRODUCTION

One of the most efficient and profitable sources of fossil fuels that contribute to supporting the world's population is the recovery of bypassed, overlooked and stranded hydrocarbons from mature reservoirs. The need to maximize the production of oil and gas from all potential sources including the better recovery of hydrocarbons in mature fields is reflected in the projection that seventy-eight percent of the U.S. energy requirements in 2035 will still come from fossil fuels (U.S. Energy Information Administration, 2009). Increasing production of oil and gas to meet these energy requirements will necessitate the utilization of advances in geoscience technologies available for new greenfield exploration, the search for unconventional resources, and improved exploitation of existing fields. Considerable efforts towards reducing geologic and economic risks in exploration and the tapping of unconventional resources such as shale gas, coalbed methane, and oil sands made feasible through improvements in completion and drilling technologies will not meet future energy requirements. Therefore, it will also be essential to increase the ultimate recovery of oil and gas from mature fields.

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This thesis follows the style of Journal of Applied Geophysics.

It is well known that large quantities of oil and gas in mature fields have yet to be recovered due to insufficient geological techniques, technologies and tools available when geologists first developed those fields. It is now thought possible that the proper application of enhanced seismic interpretation in reservoir modeling is one of the best opportunities for increasing the recovery of oil and gas from currently producing reservoirs as well as in the delineation of bypassed and stranded hydrocarbons in fine-scale structural and stratigraphic traps.

The great advantage of enhanced seismic when integrated with conventional geology is improved resolution leading to better definition of both vertical and lateral reservoir property variations. Enhanced seismic interpretation provides one of the best methodologies for the delineation of heterogeneity, connectivity and flow units in producing oil and gas fields. In addition, the increased resolution of enhanced seismic is useful for determining reservoir scale structure and stratigraphy that are not visible with conventional seismic.

Improved imaging resolutions after seismic enhancement reveal insights into reservoir heterogeneity, connectivity and flow units. Understanding reservoir heterogeneity characteristics enables a geologist to conceptualize lateral and vertical variations in rock properties that affect permeability and porosity and influence fluid flow within a reservoir. Reservoir connectivity can be determined from enhanced seismic through seismic inversion of petrophysical properties associated with effective porosity and reservoir rock. Flow units or reservoir bodies with connected porosity can be extracted from these seismic inversion volumes. Insights provided by enhanced seismic with respect to defining shape, size, and aerial extent of flow units is of critical importance in accurately modeling complex reservoirs. This knowledge of flow units is used in determining the capacity of existing wells to drain a reservoir and in the location of overlooked untapped flow units that could contain bypassed and stranded hydrocarbons.

Previous Work

Most recent heterogeneity studies of both clastic and carbonate reservoirs have utilized either of the two following geologic techniques to determine and define reservoir heterogeneity, connectivity, and flow units. Each of these techniques has advantages and disadvantages.

One technique involves using either production data or geochemical analysis to determine communication between wells and hydrocarbon provenance (e.g. Hwang, et al., 1994). The advantage of this approach is a definitive determination that any two or more wells are producing hydrocarbons from the same flow unit. However, this approach leaves uncertainty as to the configuration of the flow unit. Another problem is the lack of knowledge about the existence or characteristics of any bypassed or stranded hydrocarbons in overlooked flow units.

The other method uses seismic and other geophysical data in an attempt to image reservoir heterogeneity, connectivity and or other characteristics that affect fluid flow in three dimensions (e.g. Hart, et al., 1998; Tebo and Hart, 2005; Sarzalejo and Hart, 2006;

Hart, et al., 1997). The advantage of this method is better understanding and delineation of reservoir characteristics for determining heterogeneity and flow units in interwell regions. The disadvantage is lack of knowledge about reservoir fluid flow characteristics that can be determined with geochemical analysis and production data.

Both of the previously mentioned methodologies for determination of reservoir heterogeneities and connectivity provide only partial insight into the behavior of fluids within reservoir intervals in the subsurface. However, if both methodologies are used with enhanced seismic an even clearer image of reservoir heterogeneity, connectivity and flow units is possible resulting in better recovery factors for mature oil and gas fields.

Statement of Problem

One of the many interpretational deficiencies in reservoir models is a poor understanding of flow units, heterogeneities and connectivity within individual reservoirs. These misunderstandings can result in bypassed, overlooked, or stranded hydrocarbons in untapped reservoir flow units. This study seeks to develop a valid methodology for better identification and comprehension of reservoir connectivity, heterogeneities and flow units through the integration of seismic enhancement with more conventional analysis.

Objectives

This thesis seeks to set forth a valid methodology for the identification of reservoir connectivity, heterogeneity, and flow units through the use of seismic enhancement with conventional reservoir analysis. Specific focus will be on the integration of enhanced seismic and seismic attributes with conventional geologic interpretations for high-resolution imaging of reservoir heterogeneities and flow units in a clastic setting. Integration of published literature, outcrop analog analysis, well log analysis, and conventional seismic interpretation will be used to confirm the validity and resolution limits of seismic enhancement, as well as the construction of a reservoir model. The methodologies set forth in this study will then be used to generate an accurate reservoir heterogeneity and connectivity model with enhanced seismic data.

Methods

The methodology developed in this study integrates enhanced seismic interpretation with conventional geologic techniques for the generation of reservoir heterogeneity and connectivity models. Conventional geologic information used includes outcrop analog data, subsurface well data and conventional seismic data. Validation of the seismic enhancement is essential before enhanced seismic interpretation and generation of the reservoir models.

The first step is to review previous research to gain a comprehensive background knowledge of both the regional tectonic and depositional systems as well as knowledge of the study area. Next detailed analysis of the outcrop analog needs to be performed and applied to targeted intervals. Subsurface well data can then be analyzed for indications of vertical and lateral facies variation. Petrophyscial analysis of well data provides essential lithology and reservoir property information for comprehensive enhanced seismic interpretation. In this study, synthetic seismograms are created using the convolutional model with wavelets that either correspond to the conventional or the enhanced seismic data. The conventional synthetic seismogram is essential for determining time-depth relationships while fine adjustments with the enhanced synthetic seismogram enable the identification of reflections that correspond with reservoir intervals. Conventional seismic interpretation is used for identification of lower-order stratigraphic sequences and large structures. While enhanced seismic enables the interpretation of higher-order sequence sets and parasequences as well as small fault trends. Large-scale structures tend to be difficult to interpret in enhanced seismic volumes. Combining each of these interpretation methods allows the determination of higher and lower-order stratigraphy, large and small scale structures, as well as other reservoir characteristics necessary to contribute to the generation of a reservoir heterogeneity model. Inversion of the enhanced seismic volume and extraction of geobodies allows for the delineation of reservoir compartments and flow units.

Study Field, Dataset, and Geological Setting

In order for this analysis to have validity and to confirm the accuracy of the seismic enhancement a mature and properly understood reservoir was required. This allows for an accurate determination of the effectiveness of integrating enhanced seismic with conventional data and detailed mapping of the reservoir. To satisfy this requirement a mature onshore producing field from the Wilcox group was selected in the Gulf Coast Basin. This field, a member of the Wilcox sandstone play in the Houston Embayment, can be readily compared with the Sheridan and Katy fields in the Wilcox fault zone (Kosters, 1989; Miller, 1991). Available literature on the regional stratigraphy (Rosen, 2007; Zarra, 2007; Galloway, et al., 1994; Galloway, et al., 2000) and depositional systems (Williams, et al., 1974; Fisher and McGowen., 1969; Fisher, 1969) provide the necessary base line information for a rigorous testing of the enhanced seismic for accuracy in detecting and mapping sand-shale geometries and reservoir heterogeneities. Comparing previous work with interpretations from both conventional seismic and enhanced seismic confirmed that the use of enhanced seismic is valid for reservoir delineation in clastic environments.

Outcrop description and grain size analysis was performed at an exposure of the Upper Wilcox near Bastrop, Texas. The subsurface data consisted of wireline logs from wells between the outcrop and study area, and from wells in the study area. A small seismic survey was also used in this study. Figure 1 shows the surface geology as well as the relative locations of the outcrop and seismic survey. Figure 2 shows the subsurface stratigraphic column that will be used in this study (Galloway, et al., 2000). The stratigraphic columns for the surface and subsurface differ due to nomenclature conventions. The surface Wilcox Group does not include the Carrizo formation and was deposited during the Paleocene. The subsurface Wilcox Group is Paleocene and Eocene in age and divided into the Upper, Middle, and Lower Wilcox with the Carrizo included in the Upper Wilcox. Condensed sections and flooding events represented by specific shales are used to separate the Upper, Middle, and Lower Wilcox.

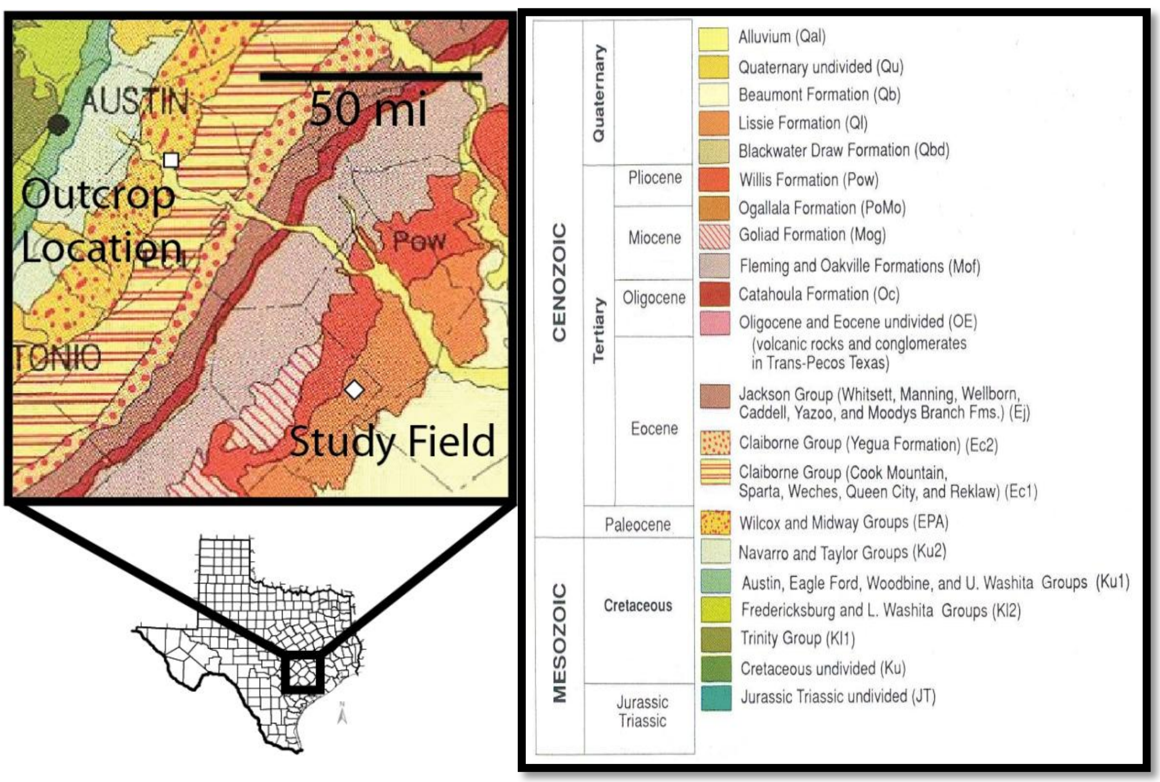


Fig 1: Approximate field and outcrop locations indicated on a geologic map of central Texas. Notice that the stratigraphic column and legend for the geologic map only pertains to the surface geology. In the subsurface Wilcox sediments can be dated in both the Paleocene and Eocene. This image was modified from a "Geology of Texas" map (Bureau of Economic Geology, 1992).

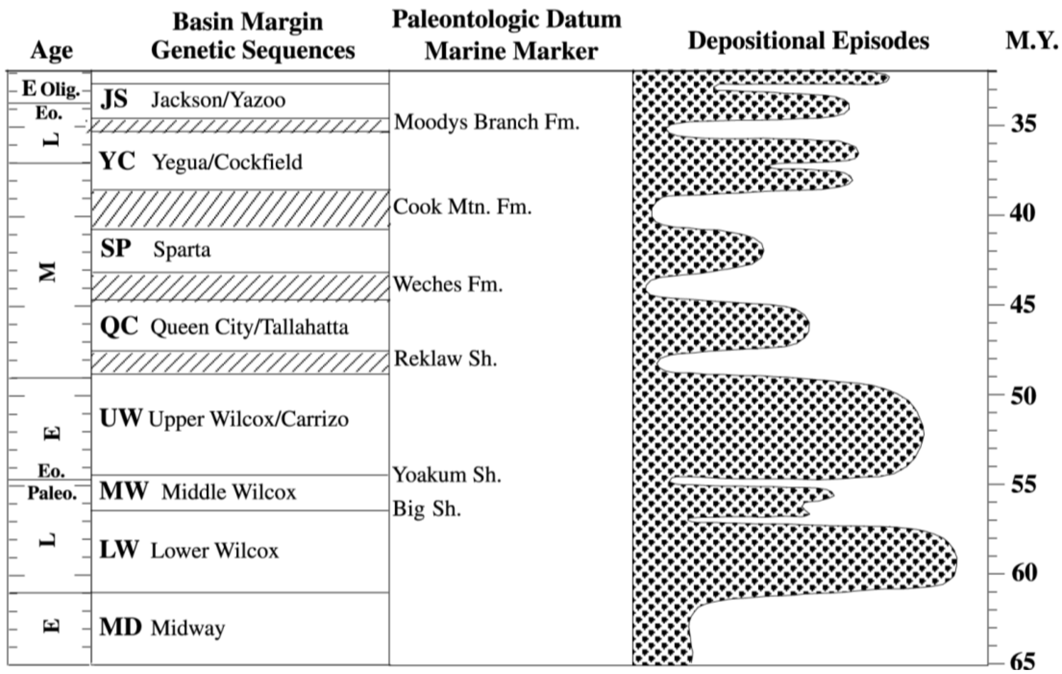


Fig 2: Stratigraphic column illustrating subsurface nomenclature as depicted by Galloway (Galloway, et al., 2000). Notice how the Wilcox is segmented into three depositional episodes separated by flooding surfaces which are associated with condensed sections.

Figure 3 illustrates the available data in the study area while Figure 4 connects the outcrop location to the northwest with the seismic survey in the southeast. Wells labeled with letters are outside of the seismic survey while wells labeled with numbers are inside the seismic survey and produce from the Frio, Upper Wilcox, and Middle Wilcox. The reservoir intervals analyzed in this study were identified in Well 4 and are referred to as the Upper Wilcox, Upper Middle Wilcox, and Middle Wilcox reservoirs. These reservoirs can be located in Well 4 between 8220ft to 8550ft, 10400ft to 10850ft, and 12,300ft to 12,400 ft subsea depth.

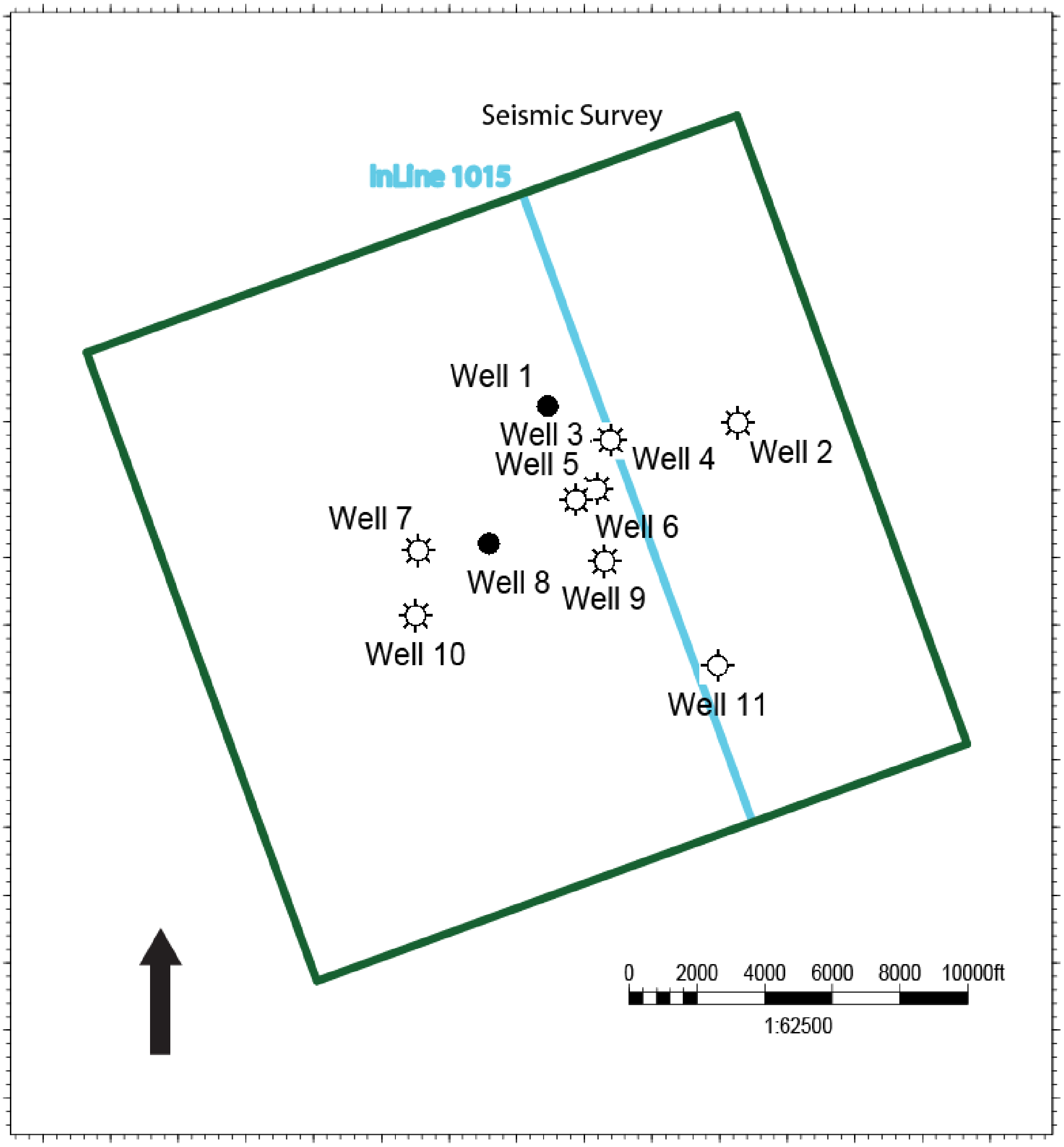


Fig 3: Study area base map showing well locations in the seismic survey. Inline 1015 intersects Well 4 and appears in several other Figures.

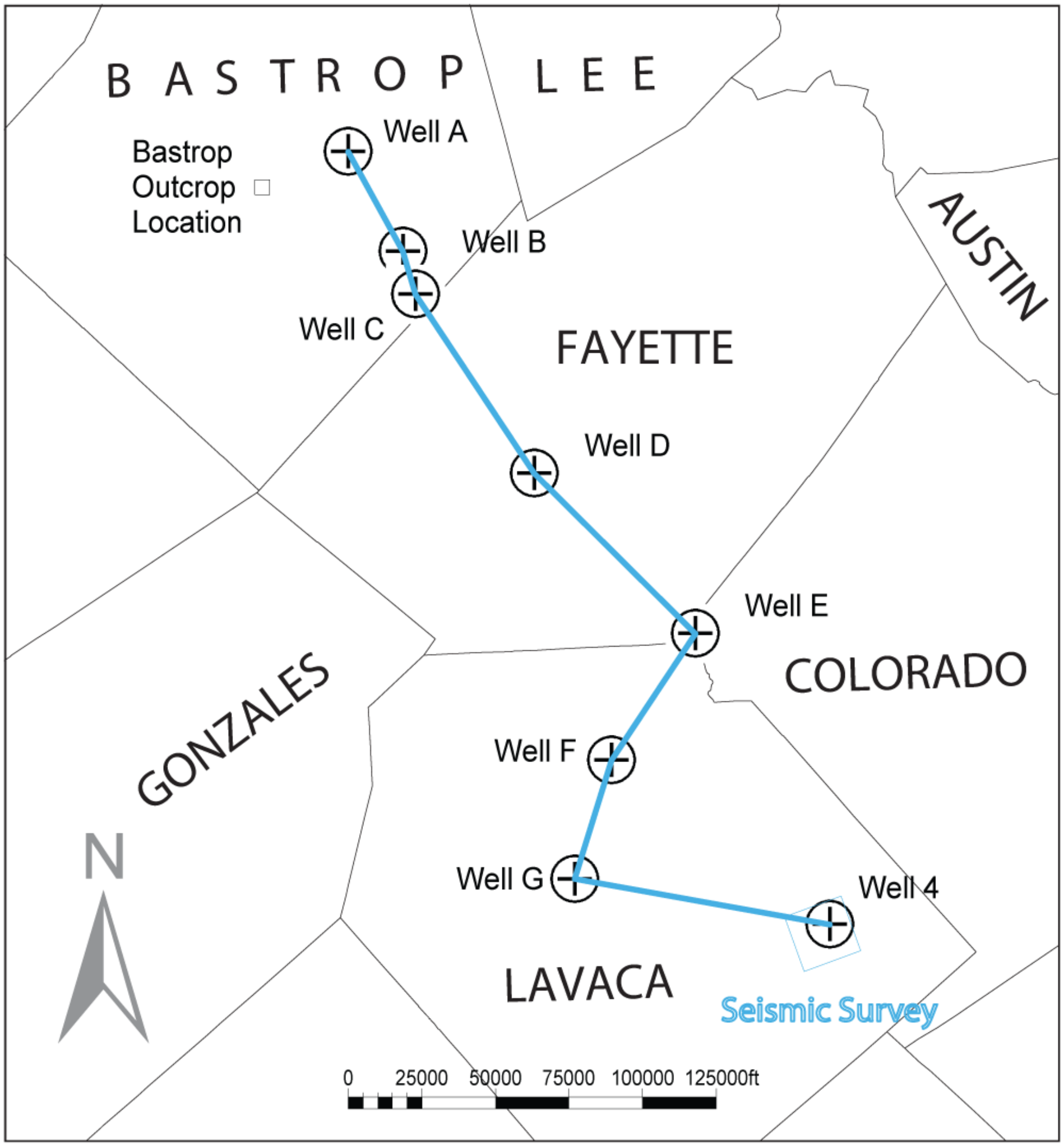


Fig 4: Regional base map showing the outcrop analog location relative to the seismic survey and study area. Wells renamed with letters are outside of the seismic survey while those with numbers are inside the seismic survey.

Understanding the regional structure and stratigraphy was essential for the enhanced seismic interpretation and generation of a reservoir heterogeneity model. Figure 5 illustrates the general structural and stratigraphic characteristics of the study area along depositional dip with a conventional seismic inline. Important features included large listric normal growth faults cutting through the Wilcox Group as well as horizons representing the Yegua, Upper Wilcox, and Middle Wilcox formation tops. The faults occur just on the basinward side of the Stewart City Cretaceous Shelf Margin in what can be called the Wilcox detachment. Few stratigraphic features are seen in the conventional seismic volume. However, previous work with well logs identified log facies, generated paleoenvironmental maps, and built depositional models which suggest that the Upper and Middle Wilcox deposition is predominately deltaic and shallow marine in nature (Xue and Galloway, 1995; Galloway, et al., 1994; Williams, et al., 1974; Galloway, 2008). Earlier geologic analysis of the Wilcox enables a focused interpretation for identifying heterogeneity, connectivity, flow units and other features that were previously overlooked due to the limits of available seismic resolution.

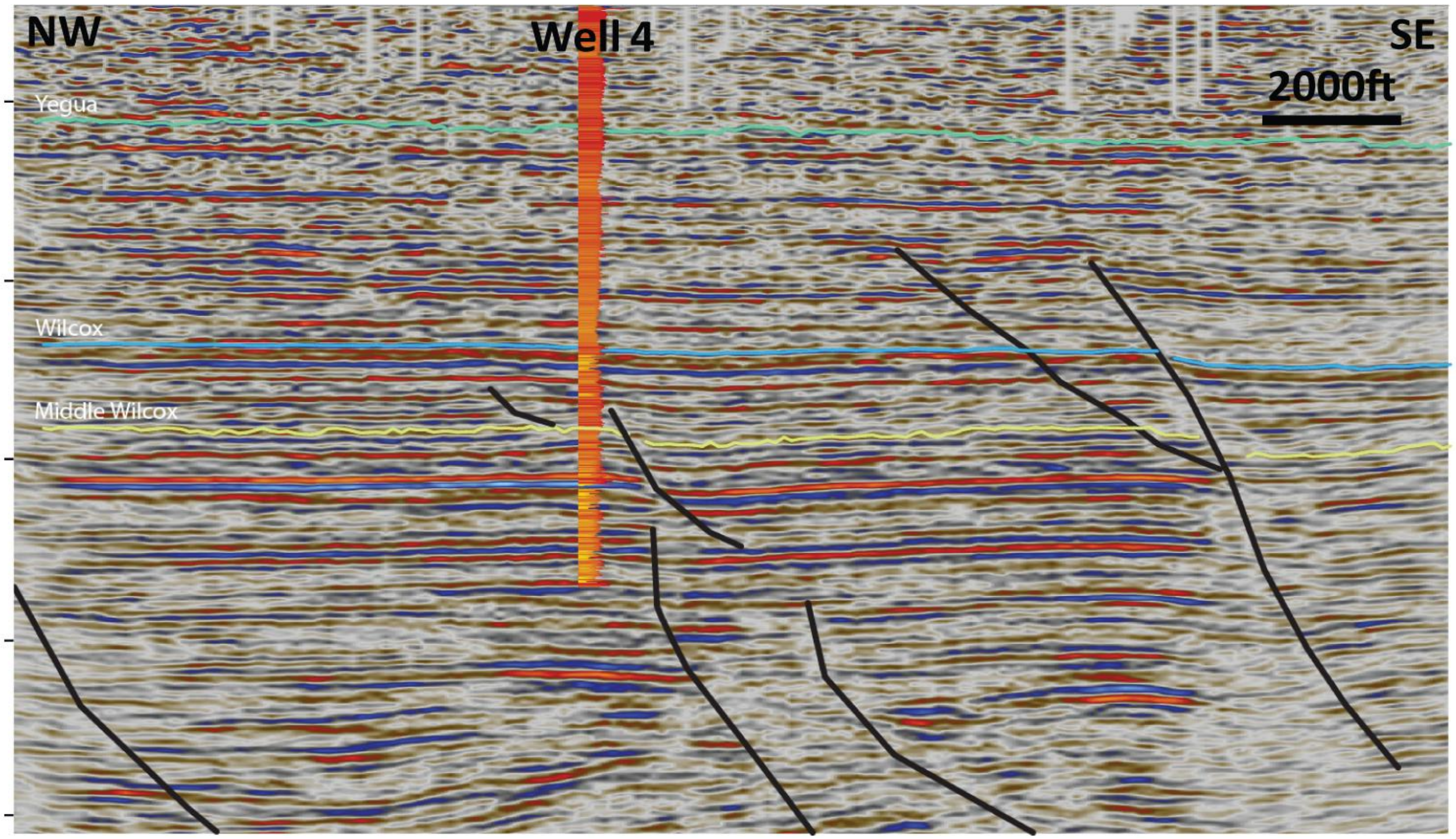


Fig 5: Seismic interpretation along depositional dip showing inline 93. The Well 4 gamma ray log is shown with yellow sands and red shales. Larger normal faults are indicated in black. The Yegua, Wilcox, and Middle Wilcox formation top horizons are also indicated.

Significance of the Study

The significance of this study lies in using enhanced seismic in conjunction with traditional exploration and development techniques for improved geologic delineation and analysis of reservoir characteristics, stratigraphy and structure. The ability to resolve finer stratigraphic and structural features with enhanced seismic enables delineation of thin connected reservoir bodies and identification of previously unnoticed reservoir heterogeneities. In addition, enhanced seismic has economic benefits associated with being a low cost geologic tool as it is derived from an existing conventional seismic data set. This allows the use of enhanced seismic where the high cost of new seismic acquisition is not economic, letting companies reevaluate mature exploration areas for bypassed, overlooked, and stranded hydrocarbons.

CHAPTER II

RESERVOIR CHARACTERIZATION METHODOLOGY

Introduction

This chapter outlines the methodology required to interpret and integrate analog data, subsurface well data, and conventional seismic with enhanced seismic for determining reservoir heterogeneity and connectivity. Key geologic features that can be delineated include depositional environments, large and small-scale structure, high and low-order stratigraphy, sand-shale geometries, as well as reservoir connectivity. Location and delineation of bypassed hydrocarbons along with development of better strategies for improving petroleum recovery are possible after the determination and mapping of reservoir heterogeneities, connectivity, and flow units.

Analog Analysis

Core and outcrop analog data that correspond to reservoir facies are vital to improved understanding of porosity, permeability, fluid flow patterns, and other reservoir characteristics. Analog analysis consisted of outcrop description, laser diffraction grain size analysis, and correlation of the outcrop facies with the subsurface. Incorporating interpretations from each of these data sources provides insight into reservoir characteristics and heterogeneities in the subsurface.

Outcrop and core descriptions can reveal reservoir features ranging from gross lithology and grain size to sedimentary structures and ichnofacies. Analysis of different reservoir characteristics from core or outcrop enables the better determination of reservoir facies that can be analyzed for indications of flow barriers, depositional environments, stratigraphic surfaces, and other characteristics. Analog descriptions followed the methodology outlined in the AAPG Sample Examination Manual (Swanson, 1981). The focus of analog analysis is to identify depositional environments, stratigraphic surfaces and sedimentary structures for understanding how similar features in the subsurface might affect seismic reflections, facies, and reservoir characteristics.

Permeability and porosity can be directly measured in core. However, this study uses laser diffraction grain size analysis on an outcrop analog since core is unavailable. Laser diffraction grain size analysis was performed on disaggregated samples to generate quantitative grain size distribution curves that were then used to determine mean grain size and sorting. More detailed petrographic analysis was not performed since exposure effects on analog samples would not be present in the subsurface. Mean grain size and standard deviation can be determined from the distribution curves with the following equations after grain size is converted from microns to phi scale (Folk and Ward, 1957):

$$\textit{Mean Grain Size} = \frac{\emptyset_{16} + \emptyset_{50} + \emptyset_{84}}{3}$$

$$\textit{Inclusive Graphic Standard Deviation} = \frac{\emptyset_{84} - \emptyset_{16}}{4} + \frac{\emptyset_{95} - \emptyset_{5}}{6.6}$$

The $\emptyset_n$ values represent the phi grain size at the n^{th} percentile from the distribution curves generated by laser diffraction. Grain sorting can be determined from standard deviation (Folk, 1980). This high resolution technique provides excellent instrumental precision; however, grain size dispersal curve quality is dependent on sample preparation (Sperazza, et al., 2004). In clastic systems like the Upper Wilcox, disaggregation can be achieved through agitation and chemical treatments with HCl and H_2O_2 to remove calcite and organics. The lack of cementation and significant digenesis at the outcrop location suggested that this disaggregation method would be useful. After completion of the study several samples were treated with Na_2SiO_3 and reprocessed. This additional step was used because some silt and clay aggregates did not respond to treatment with HCl and H_2O_2. The silt and clay aggregates affected the grain size results by slightly increasing mean grain size and reducing sorting in some silt dominated samples.

Outcrop or core analysis often involves relating geologic descriptions with geophysical well logs. Core samples have the benefit of being associated with specific locations; outcrop analogs, on the other hand, must be correlated with the subsurface. This was accomplished by correlating the mean grain size curve with shale content derived from gamma ray and spontaneous potential logs from a nearby well. It is found, however, that most of the time spontaneous potential logs are difficult to use for this purpose because similar formation water and drilling mud resistivity mask sand signatures in the shallow subsurface. The accuracy of this correlation is determined by cross-plotting shale content derived from gamma ray measurements with mean grain size from the outcrop. Regional correlations from outcrop analog analysis provide insight into how the analog interpretation might need to be altered for this application.

Well Log Analysis

Several types of well log analysis are required for this heterogeneity study. The first use of well logs is in the application of the outcrop analog analysis to the study area. This provides insight into the usefulness of the analog analysis by correlating from the outcrop location to nearby wells and the study area. The second well log analysis consists of a formation evaluation for selected reservoir intervals.

Petrophysical analysis is essential for the identification of reservoir intervals and interpretation of the seismic data. Shale content, connectivity, and water saturation were all calculated using the following equations (Asquith, et al., 2004):

$$V_{sh} = \frac{GR_{log} - GR_{Sand}}{GR_{Shale} - GR_{Sand}}$$

$$S_w = ((a \times R_w / {\varphi_E}^m)/R_D)^{(1/n)}$$

where V_{sh} is the shale content or shale percentage. Since shale is impermeable, connectivity of pore spaces can be defined by multiplying porosity with sand percentage as follows:

$$Connectivity = \left(\frac{\rho_m - \rho_b}{\rho_m - \rho_f}\right) \times (1 - V_{sh})$$

The ρ_b term represents bulk density from the well log while ρ_m and ρ_f represent matrix and fluid density respectively. This estimation identifies likely porous and permeable layers that permit fluid flow. The S_w or water saturation log was used to identify the presence of hydrocarbons in the subsurface. The gas effect detected by density neutron crossover was also evaluated. From these calculations potentially productive zones were identified. Good producible reservoirs are composed predominately of sand, have higher porosity and connectivity, and low water saturations. The cut off parameters used for identification of productive sand bodies were shale volumes less than 60%, water saturation less than 50%, and porosity greater than 10%.

Synthetic Seismogram Analysis

Synthetic seismogram analysis assists in the determination of seismic resolutions, time-depth relationships, and the lithologic identification of important seismic reflections. The convolutional model is utilized to generate synthetic seismograms which are matched to extracted traces from either the conventional or enhanced seismic volume. This provides a one dimensional seismic interpretation enabling the creation of accurate well time-depth relationships.

The convolutional model is utilized to generate a synthetic seismogram as illustrated in the figure on page 22. The following convolutional model equations require the presence of both sonic ($1/V_p$) and density (ρ) logs (Yilmaz, 1987):

$$AI = V_p \times \rho$$

$$RC = \frac{AI_2 - AI_1}{AI_2 + AI_1}$$

$$Synthetic\ Seismogram = RC * Wavelet$$

AI represents the acoustic impedance and *RC* represents the reflection coefficient. Figure 6 also illustrates how synthetic seismograms are used to create accurate well time-depth relationships through matching of the synthetic seismograms with extracted traces along the wellbore.

The determination of data resolution is also accomplished through the use of synthetic seismograms. This is possible because synthetic seismograms allow for the determination of dominate frequency and direct comparison of wireline log data with seismic. Combining these observations with previous work on seismic resolution allows the comparison of observed synthetic seismograms and extracted seismic traces with theoretical resolutions estimated with the following equations (Widess, 1973; Yilmaz, 1987; Kallweit and Wood, 1982):

$$\lambda = \frac{V}{f}$$

$$Separable\ Beds\colon Thickness \geq \frac{\lambda}{4}$$

$$Visible\ Beds\colon Thickness \geq \frac{\lambda}{8}$$

Since seismic resolution is dependent on dominate wavelength, λ, the first step is to use well and seismic data to obtain reasonable seismic velocities, V, and frequencies, f. Separable resolution refers to the identification of the top and base of a bed while visible resolution refers to the identification of a bed with a single reflection. In some cases resolution limits may be higher or lower due to interference from processing effects or noise. Application of these equations and observations of synthetic seismograms enable the determination of seismic resolutions.

Seismic interpretation in one dimension is also possible through the use of synthetic seismograms. This is important because synthetic seismograms enable the identification of significant surfaces or contacts in seismic data. For instance, the synthetic seismogram indicates that the trough in Figure 6 located at 1690ms two way travel time (TWT) represents a shale interval where acoustic impedance increases dramatically. Similar interpretations allow for the identification of reservoir reflections.

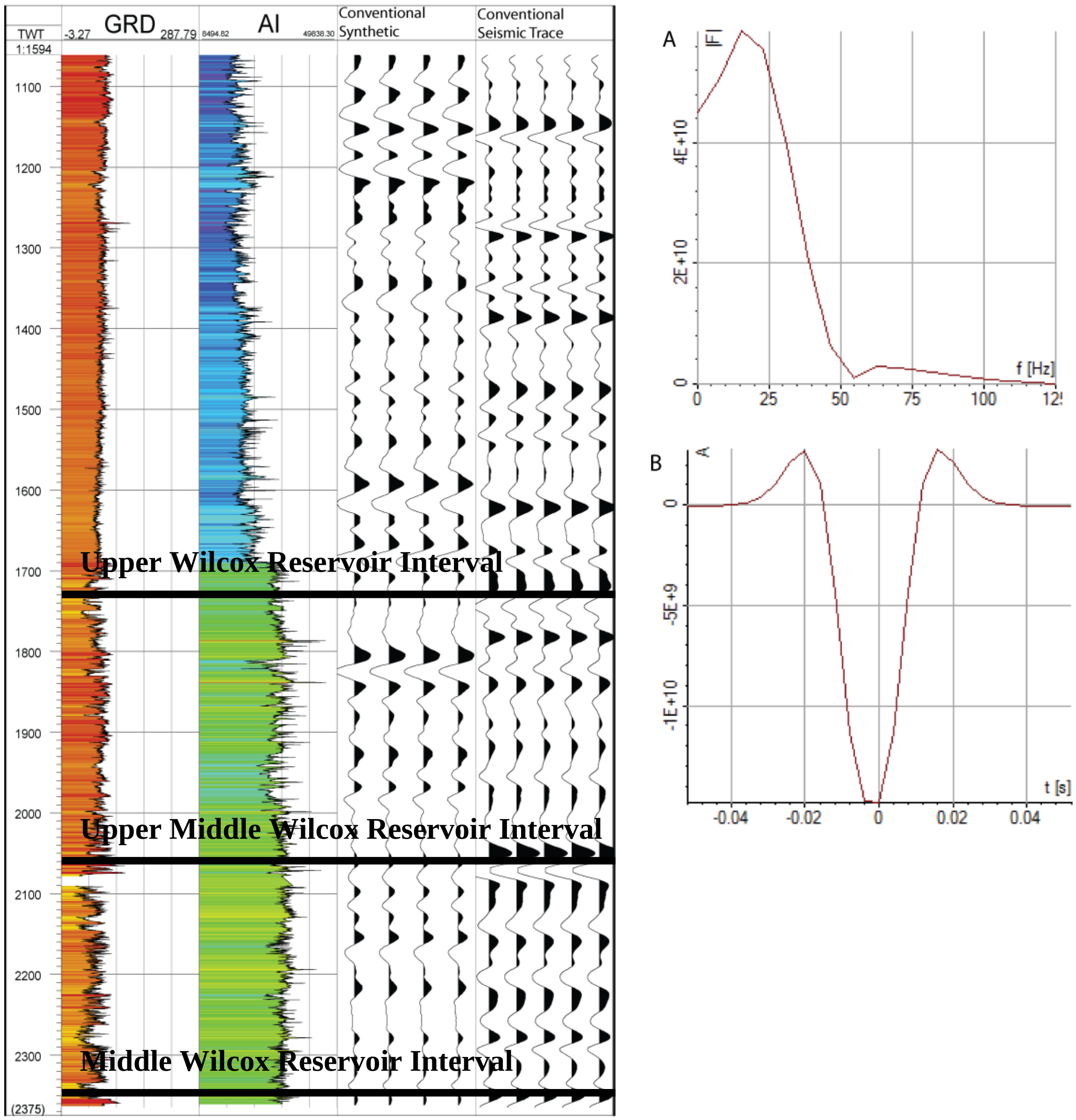


Fig 6: Synthetic seismograms produced using the convolutional model. From right to left, gamma ray, acoustic impedance, conventional synthetic seismogram, and conventional seismic trace for Well 4 are shown. A indicates the frequency spectrum of the convolutional seismic while B indicates the wavelet used during convolution.

Conventional Seismic Analysis

Conventional seismic interpretation for this study was divided into stages. The first stage involves validation of the geologic consistency of the seismic enhancement. Using geologically consistent conventional and enhanced seismic data, the second stage is to identify large-scale geologic features that are more accurately and easily interpreted with conventional seismic. These geologic features need to be delineated and incorporated into the reservoir model.

Interpretation for validation of the seismic enhancement consists of identification of seismic facies, significant stratigraphic surfaces and structural features. Seismic facies are identified based on reflection patterns while stratigraphic surfaces are represented by features like truncation, onlap, downlap, and offlap. Offsets between reflections in conventional seismic indicate significant large-scale faults. Features identified during conventional seismic interpretation should have analogs on the enhanced seismic data.

Previous studies comparing enhanced seismic and conventional seismic find that large-scale structural features like folds and faults can often be more accurately interpreted with conventional seismic (Sun, et al., 2003). Fine-scale stratigraphic and structural features revealed in enhanced seismic can sometimes hinder large-scale structural interpretation

Structure contour maps were generated with conventional seismic along reflections that were identified through either synthetic seismograms or bright spots.

Bright spots are often caused by fluid effects on acoustic interfaces and are easily identified on an envelope attribute volume. Faults were identified through both reflection offset and the generation of a conventional seismic coherency volume.

Seismic Enhancement

Post-acquisition enhancement of the conventional seismic volume via special processing is utilized as a means of significantly increasing the resolution of the seismic data. This seismic enhancement enables the identification of more subtle stratigraphic and structural features that otherwise cannot be observed in conventional seismic. The procedure for this enhancement is amplitude preserving neural network implementation of solving the Volterra integral equation of the first kind from a plane-wave solution of poro-viscoelasticity (Sun, et al., 2003). This amounts to what can be considered an advanced spiked deconvolution of the conventional seismic data. While this study does not venture into the details for creating enhanced seismic data, several important features are worth mentioning. The first is that the original data underwent a non-linear interpolation before enhancement in order to accommodate both vertical and lateral resolution improvements. The second pertains to the enhancement generating broader frequency bandwidth to reveal seismic expressions of fine-scale geologic features in the subsurface.

The seismic interpolation of this data set consisted of adding eight traces for each existing seismic trace as illustrated in Figure 7. This increased the space available for horizontal resolution improvement. The interpolation also decreased the sample spacing vertically from 4ms to 1ms making space for vertical resolution improvements. These modifications did not alter the conventional seismic data. However, the modifications did have significant effects on the calculation of seismic attributes. Decreasing the sample interval altered the calculation of instantaneous attributes. Decreased spacing between traces altered multi-trace attributes like coherency.

The effects of the seismic enhancement are illustrated in Figure 8 where there is a comparison of a conventional seismic trace with an enhanced seismic trace and synthetic seismograms of various dominate frequencies. The conventional seismic trace shown on the far left of Figure 8 has relatively low seismic resolution while the enhanced seismic trace on the far right of Figure 8 has significantly improved seismic resolution. The synthetic seismograms between the conventional and enhanced traces were created using Ormsby wavelets with frequency spectrums ranging from 5Hz-10Hz-25Hz-50Hz to 5Hz-10Hz-75Hz-125Hz. Note that as the frequency spectrum increases and broadens more reflections from the sand-shale interfaces can be resolved. By increasing the sample spacing and seismic resolution through this enhancement methodology geologic features that were not previously visible on the conventional seismic can be identified, delineated, and mapped.

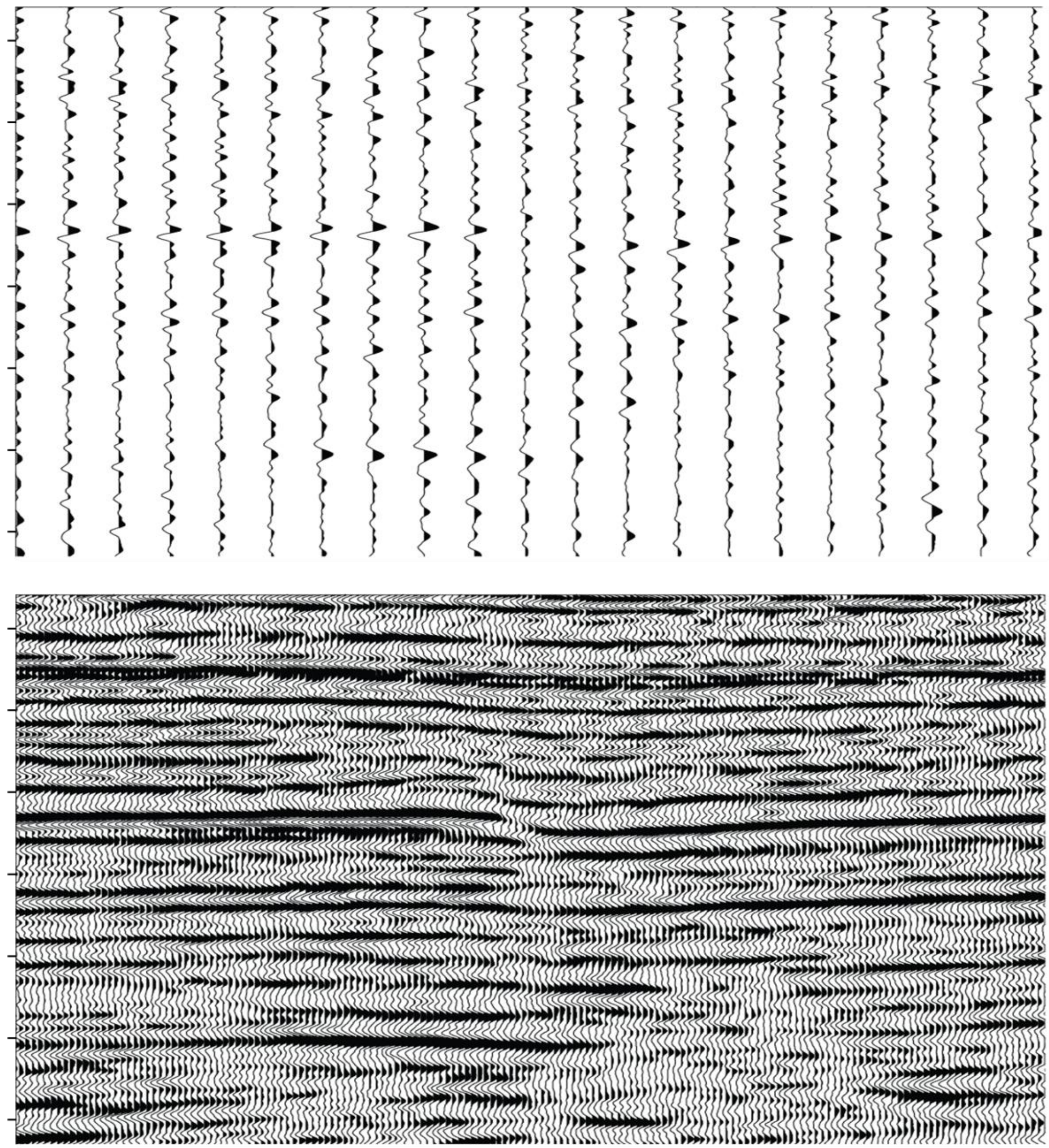


Fig 7: Illustrates effects of seismic interpolation comparing the original inline 93 with the identical interpolated inline 1023. In these images every fourth trace is shown.

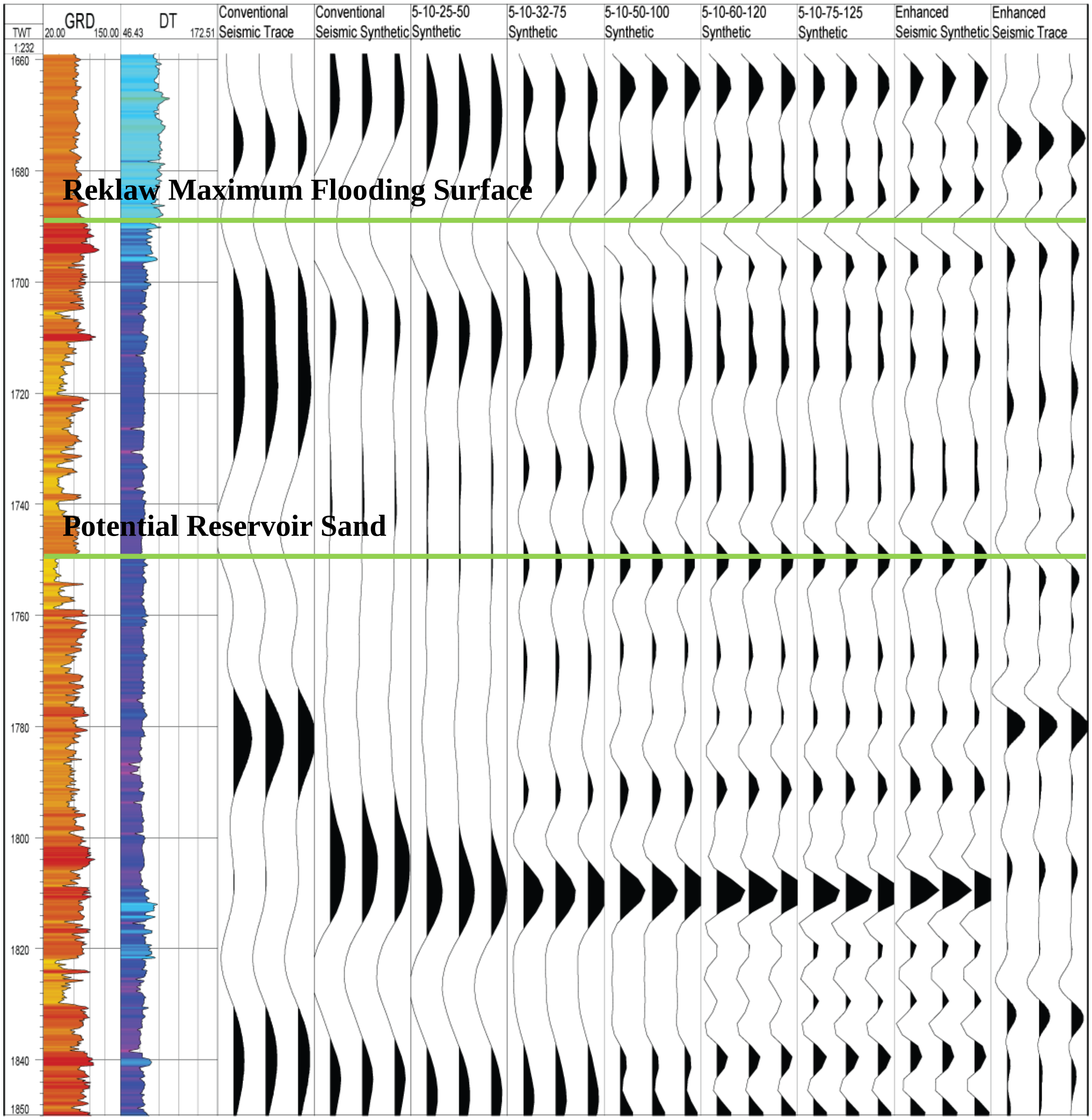


Fig 8: Effect of seismic enhancement on thin bed identification. Dominate frequencies increase from 16Hz to 65Hz. Major stratigraphic surfaces like the Recklaw shale condensed section are preserved throughout the enhancement. Individual sands like the potential reservoir sand marked are not resolvable in conventional seismic, but they are in the enhanced seismic.

Enhanced Seismic Analysis

The enhanced seismic interpretation methodology is remarkably similar to conventional seismic interpretation methodologies; however, enhanced seismic data has different inherent limitations and benefits. For instance, visualization and mapping of large-scale regional features in enhanced seismic can be challenging. Consequently, enhanced seismic interpretation generally focuses on identification of smaller geologic features limited in area or to specific reservoirs. For example, structural characteristics identified in enhanced seismic can include secondary faults associated with the large normal faulting and the creation of rollover anticlines. These secondary faults and other smaller structural features can be numerous and have offsets that are below the resolution of conventional seismic data. While mapping them is often difficult it is still worthwhile as these small geologic features can be potential flow barriers, particularly for thin reservoir sands. One side effect is that enhanced seismic coherency volumes in structurally complex areas do not image large structures clearly due to effects associated with secondary structures.

Another implication of increasing seismic resolution significantly in the enhanced seismic is appearance of more detailed stratigraphy when compared to the conventional seismic. Since surfaces identified in the conventional seismic are present in the enhanced seismic, they serve as scaffolding for continued stratigraphic interpretation. Using this scaffolding enables further interpretation within the reservoir that can reveal details indicative of approximate sand geometries, flow barriers, or other heterogeneities.

Since the enhancement preserves seismic amplitude data, techniques related to the expression of fluids in conventional seismic are still applicable with enhanced seismic. The use of an enhanced seismic envelope attribute, well data, and synthetic seismograms can determine if relationships exist between reservoir sands and anomalous seismic amplitudes. If charged sand beds can be correlated with high amplitude reflections, interpretation utilizing seismic bright spots can be used to assist both reservoir heterogeneity and fluid identification.

Integration of these enhanced seismic interpretation methods provides the ability to determine more subtle reservoir characteristics that can affect fluid movement. Sand geometry and thickness predictions can be compared with structural interpretations to determine likely trapping mechanisms and how tortuous the path is from one section of a reservoir to another. Fluid effects like bright spots when compared to reservoir geometry might reveal oil-water contacts.

Reservoir Connectivity and Heterogeneity Analysis

Reservoir heterogeneity can be determined through the integration of analog data, well data, conventional seismic, and enhanced seismic interpretations. Each data type provides key elements for the creation of a reservoir heterogeneity model. Analog analysis and well data provides detailed formation evaluations, time-depth relationships, and an understanding of depositional facies. Conventional seismic provides a means of delineating large-scale structures such as major faults, anticlines, and synclines. Enhanced seismic provides the ability for a geoscientist to discern subtle structures, seismic facies, and stratigraphy. After integrating these interpretations the characteristics of potentially productive reservoir intervals can be determined.

Reservoir connectivity can only be determined after reservoir property attributes have been identified and characterized. Once this is accomplished genetic inversion utilizing neural network and genetic algorithm training can provide a statistical approximation of these reservoir property attributes throughout the subsurface. Reservoir flow units can then be extracted from the enhanced seismic genetic inversion identifying connected regions or flow units that meet the required reservoir heterogeneity parameters. Hydrocarbon volumes can be calculated in these reservoir flow units permitting the estimation of in place resources for untapped reservoirs as well as the calculation of recovery factors for tapped flow units.

The procedure for determining hydrocarbon volumes in charged reservoir bodies in clastic systems utilizes the following equation and requires knowledge of the hydrocarbon-water contact as well as genetic inversion volumes for shale content, water saturation (S_w), and porosity (φ):

$$Hydrocarbons\ in\ Place = \frac{(Geobody\ Volume) * \varphi * (1 - S_W)}{\beta_{hydrocarbons}}$$

The geobody volume in clastic systems is extracted from the genetic inversion of V_{sh} where the shale content is just low enough to permit fluid flow. Any portion of this volume beneath the hydrocarbon water contact is removed and the remaining volume is converted from the time domain into the depth domain. $\beta_{hydrocatbons}$ represents the formation volume factor for either oil or gas. These calculations should provide a more accurate estimation of in-place hydrocarbons and recovery factors of various productive intervals. Since S_W and φ are unreliable in areas without significant well control, more general estimations need to be used for those untapped flow units.

Conclusion

The combination of several analyses and calculations provide a methodology that enables the creation of reservoir heterogeneity models as well as the delineation of potential reservoir bodies. This method integrates analog data, subsurface well data, conventional seismic, and enhanced seismic providing a better understanding of reservoir geometries and flow characteristics.

CHAPTER III

VALIDATION OF ENHANCED SEISMIC

Introduction

Validation of the seismic enhancement is required for confidence in enhanced seismic interpretation and analysis. There are several tests that confirm the geologic consistency of the enhanced seismic data. Since seismic enhancement is independent of well data, synthetic seismograms provide a one dimensional validation along the wellbore. Amplitude preservation after the enhancement is critical for genetic inversion and fluid effect analysis. Accuracy and consistency of amplitudes and geologic features can be confirmed by comparing conventional and enhanced envelope attribute volumes. Structural and stratigraphic features present in the conventional seismic should also be present in the enhanced seismic. Identification of these features in both volumes is critical. New features in the enhanced seismic should fit experimental or published regional models. Positive results from these various tests can strongly indicate that the enhanced seismic is geologically consistent.

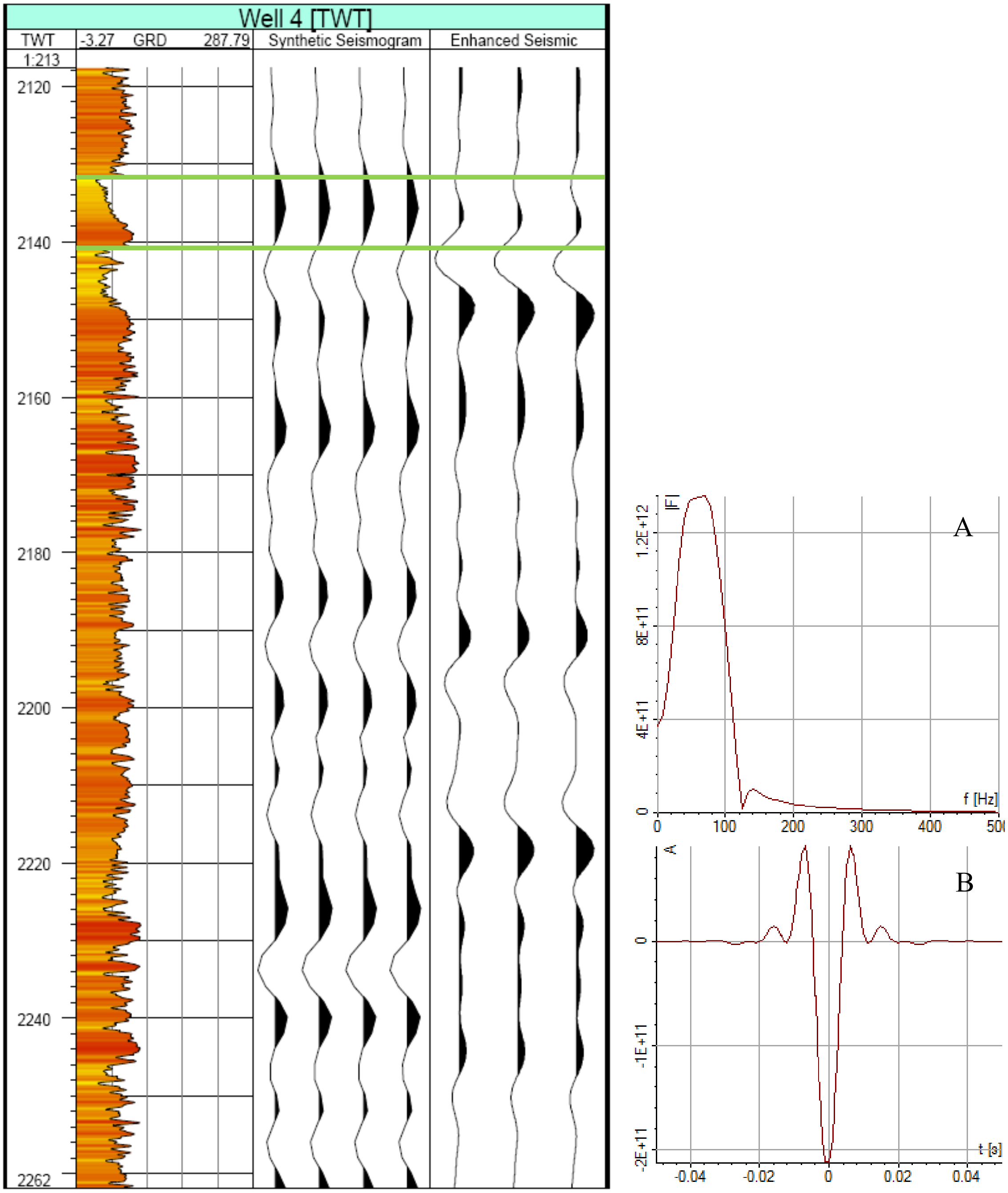


Fig 9: Validation of enhanced seismic through matching of high frequency synthetic seismograms with enhanced seismic traces along Well 4. Notice how sand tops can be identified by troughs as indicated by the green lines. Also included are the frequency spectrum for the enhanced seismic (A) and enhanced seismic wavelet (B).

Synthetic Comparison

Since the seismic enhancement is independent of well data, comparisons between high frequency synthetic seismograms and enhanced seismic traces can determine if identifiable acoustic interfaces are present in the enhanced seismic data. Figure 9 illustrates several examples along Well 4 that demonstrate a clear correlation between the synthetic seismograms and enhanced seismic data. This confirms that the enhancement is sufficiently reliable along the wellbore allowing further interpretation.

Amplitude Preservation

Creation of genetic inversions for reservoir connectivity analysis requires preserved amplitudes in the enhanced seismic data. Direct observation of amplitude preservation along with conservation of structural and stratigraphic features is achievable by comparing conventional and enhanced seismic envelope volumes as shown in Figure 10. Notice the similar bright spots and fault offsets. This test verifies that the seismic enhancement preserved both amplitude data and the presence of geologic features that were apparent in the conventional seismic.

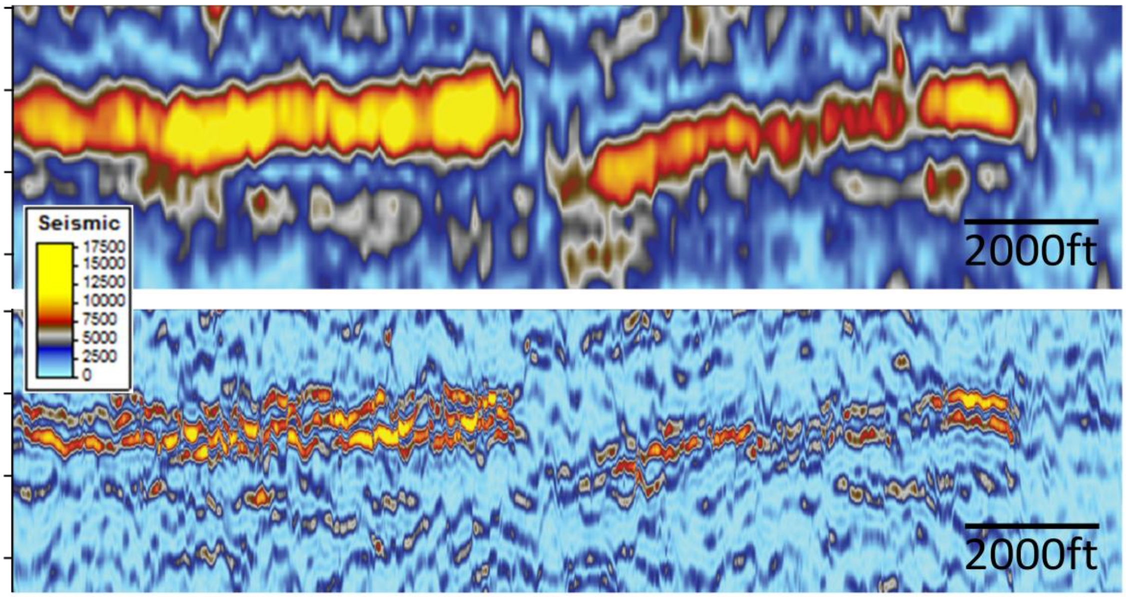


Fig 10: Confirmation of amplitude preservation and geologic feature conservation after enhancement. Conventional (top) and enhanced (bottom) envelope attribute seismic volume comparison illustrates two dimensional enhancement validation.

Surface Comparison

The surface mapped for comparison between the enhanced seismic and conventional seismic data is located near the Reklaw condensed section just above the Upper Wilcox. Sonic velocities and rock densities increase dramatically at this surface making it easier to trace in enhanced seismic. Synthetic seismograms from both volumes indicate that the surface is a trough due to the reversed polarity of the conventional seismic data. Figure 11 shows this surface as mapped with both conventional and enhanced seismic. Visual comparison indicates that these surfaces nearly mirror each other. Except along the faults and at the edges of the dataset the surfaces are within ±5ms of each other. This confirms that the large-scale geologic structures and stratigraphic surfaces in both the conventional and enhanced seismic are essentially identical.

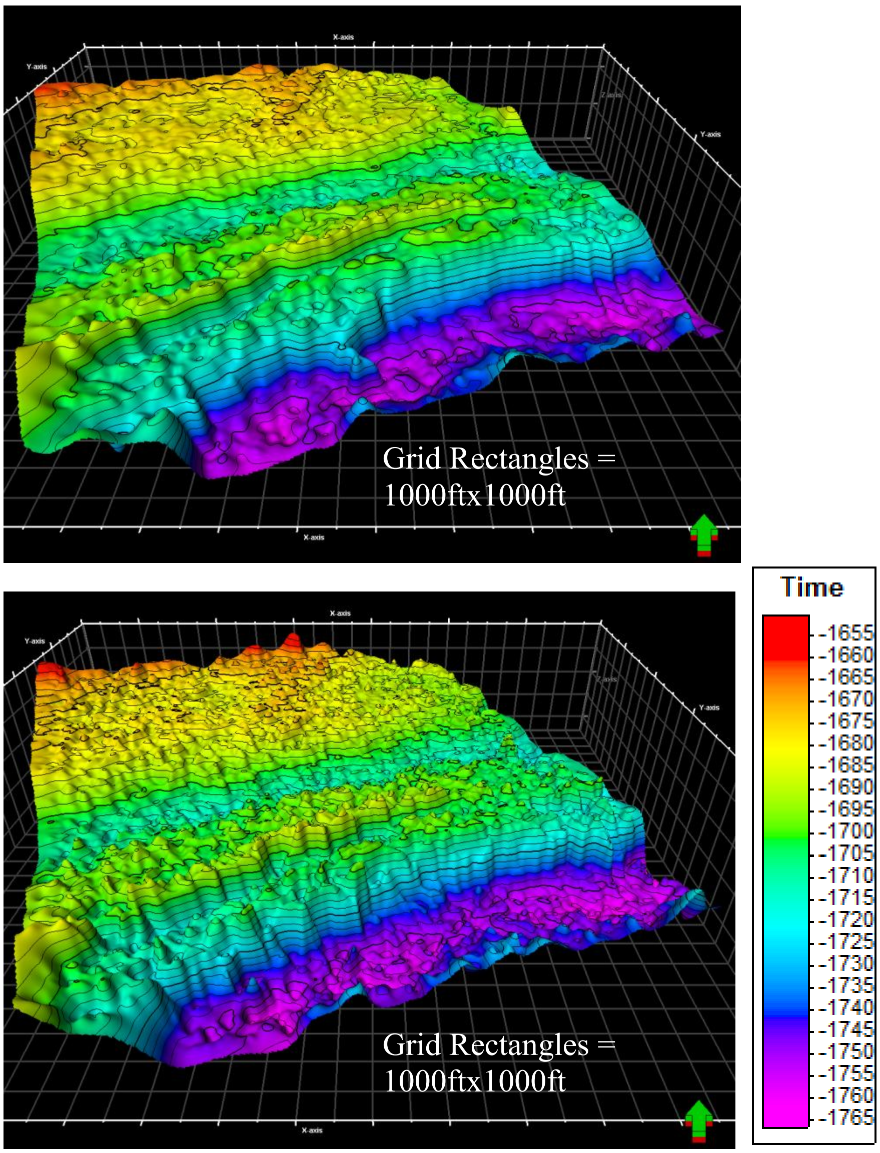


Fig 11: Enhancement validation through flooding surface comparison showing three dimensional geologic feature conservation. Conventional seismic interpretation (top) and enhanced seismic interpretation (bottom) of a maximum flooding surface.

Structural Confirmation

While not present in the conventional seismic, many secondary faults are present in the enhanced seismic volume. Formation of these secondary faults occurs during the creation of both fault-propagation folds and fault-bend folds. The existence of these secondary faults in enhanced seismic makes interpretation challenging. Secondary faults can potentially isolate thin reservoir sands by blocking fluid flow. Structural models of similar extensional regimes indicate expected secondary fault patterns in the study area as shown in Figure 12 (Withjack, et al., 2007). Figure 13 illustrates conventional seismic fault interpretation for a section of inline 1015 where two faults are visible. The smallest visible fault offset for conventional seismic is around 82ft. The same section in enhanced seismic, as shown in Figure 14, contains the large-scale faults and numerous secondary faults with offsets as low as 23ft. The fault patterns in the enhanced seismic are consistent with those of experimental models for similar extensional regimes. This consistency confirms that many secondary faults are not artifacts from the enhancement and should be considered in reservoir heterogeneity analysis.

Conclusion

By comparing enhanced seismic with conventional seismic and understood structural patterns, a determination can be made that seismic enhancement is geologically relevant in structurally complex clastic settings. The inclusion of enhanced seismic with other geologic data provides more in-depth insight into reservoir characteristics that can help locate bypassed hydrocarbons.

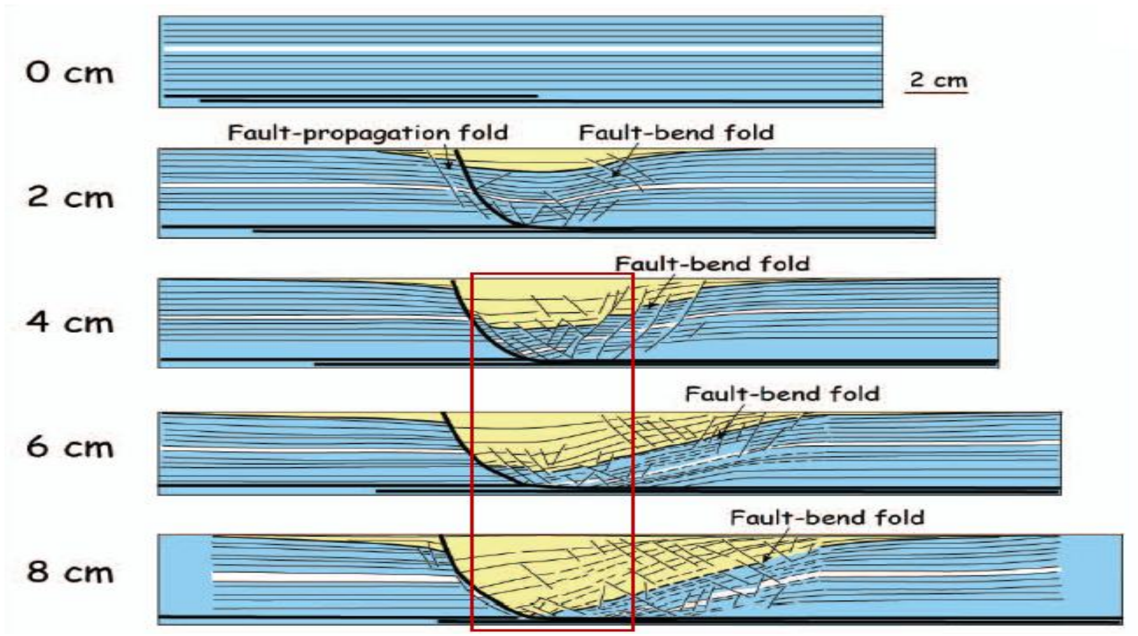


Fig 12: Experimental model for a tectonic setting similar to the study area. Faults revealed after seismic enhancement conform to the experimental model. These five images show sand and clay models of extensional settings with the red box outlining where the study area fits into the model. (Withjack, et al., 2007)

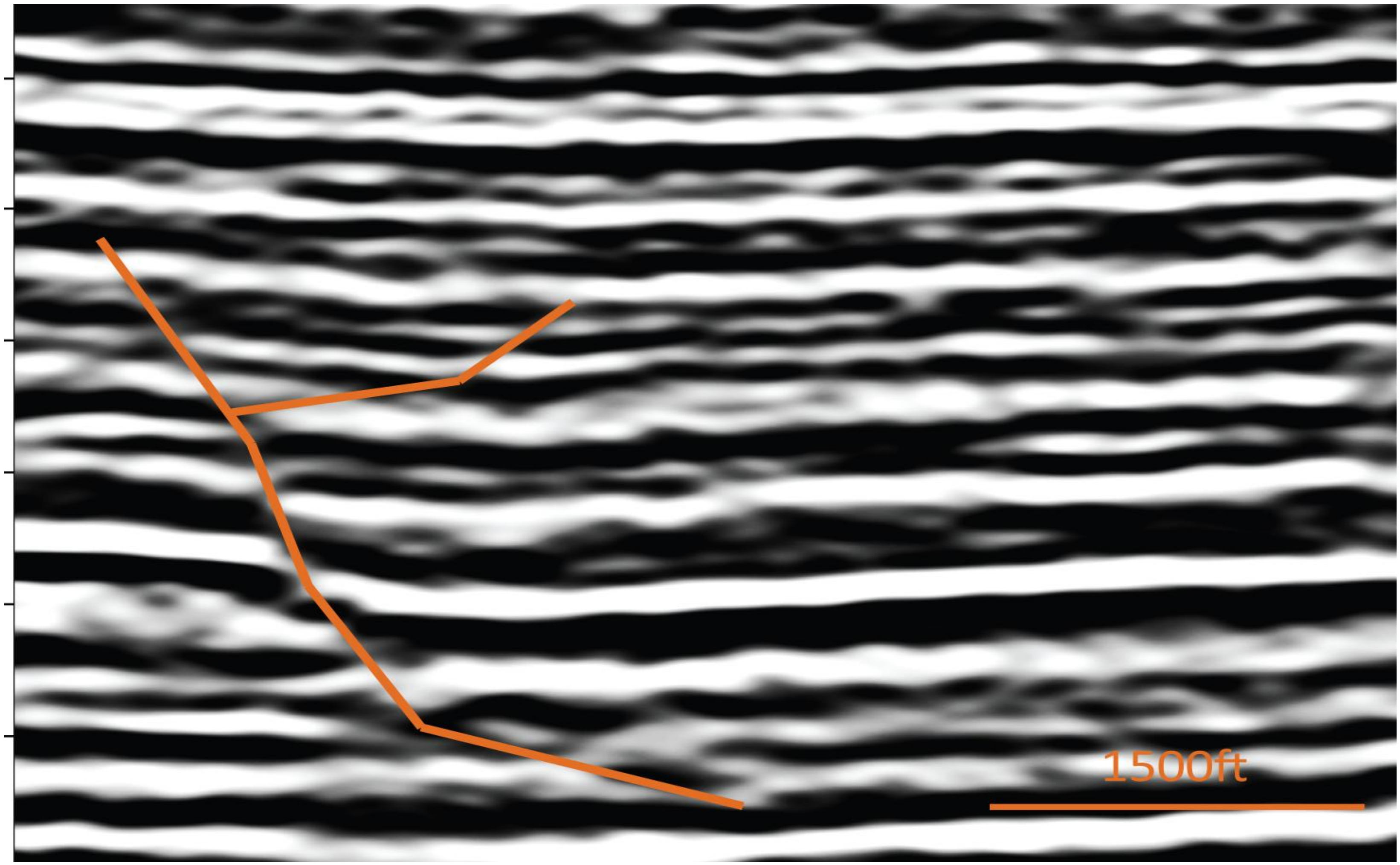


Fig 13: Conventional seismic inline 1015 with some faults indicated. Visible faults have offsets ranging from 325ft to 82ft

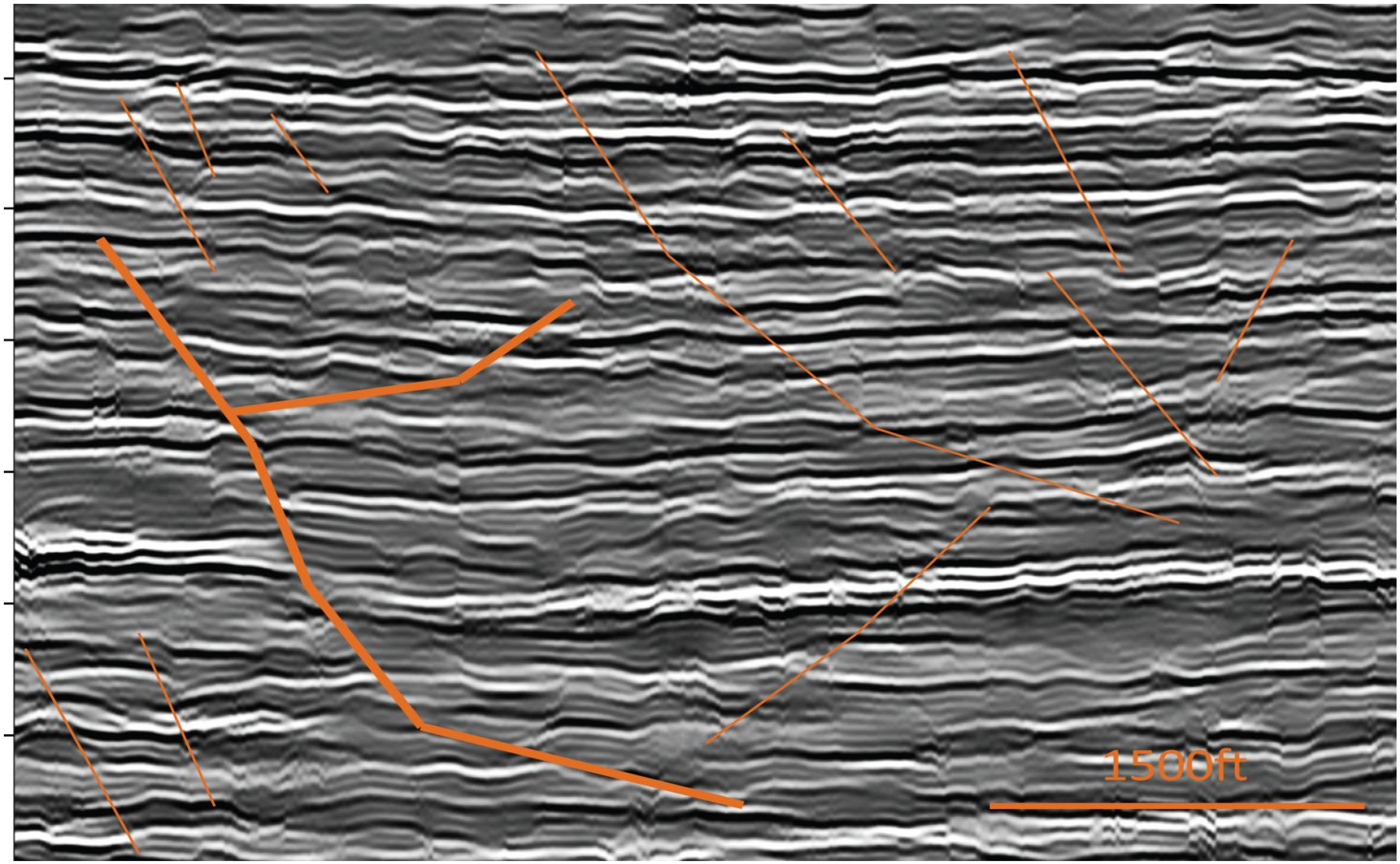


Fig 14: Enhanced seismic inline 1015 with some faults indicated. Visible faults have offsets ranging from 325ft to 23ft

CHAPTER IV

UPPER WILCOX OUTCROP ANALOG ANALYSIS

Introduction

In this study an outcrop of the Wilcox group containing exposures of the Calvert Bluff and Carrizo formations in Bastrop, Texas, was analyzed for characteristics that contribute to an improved understanding of reservoir heterogeneities. This analog analysis included a description of outcrop sedimentary features as well as quantitative laser diffraction grain size analysis. Analog studies impart an understanding of reservoir heterogeneities that are not apparent at conventional and enhanced seismic resolutions. The analog study provides insight into seismic results by characterizing depositional and stratigraphic features that contribute to acoustic contrasts and seismic reflections. These interpretations are essential for determining the viability and usefulness of seismic enhancement.

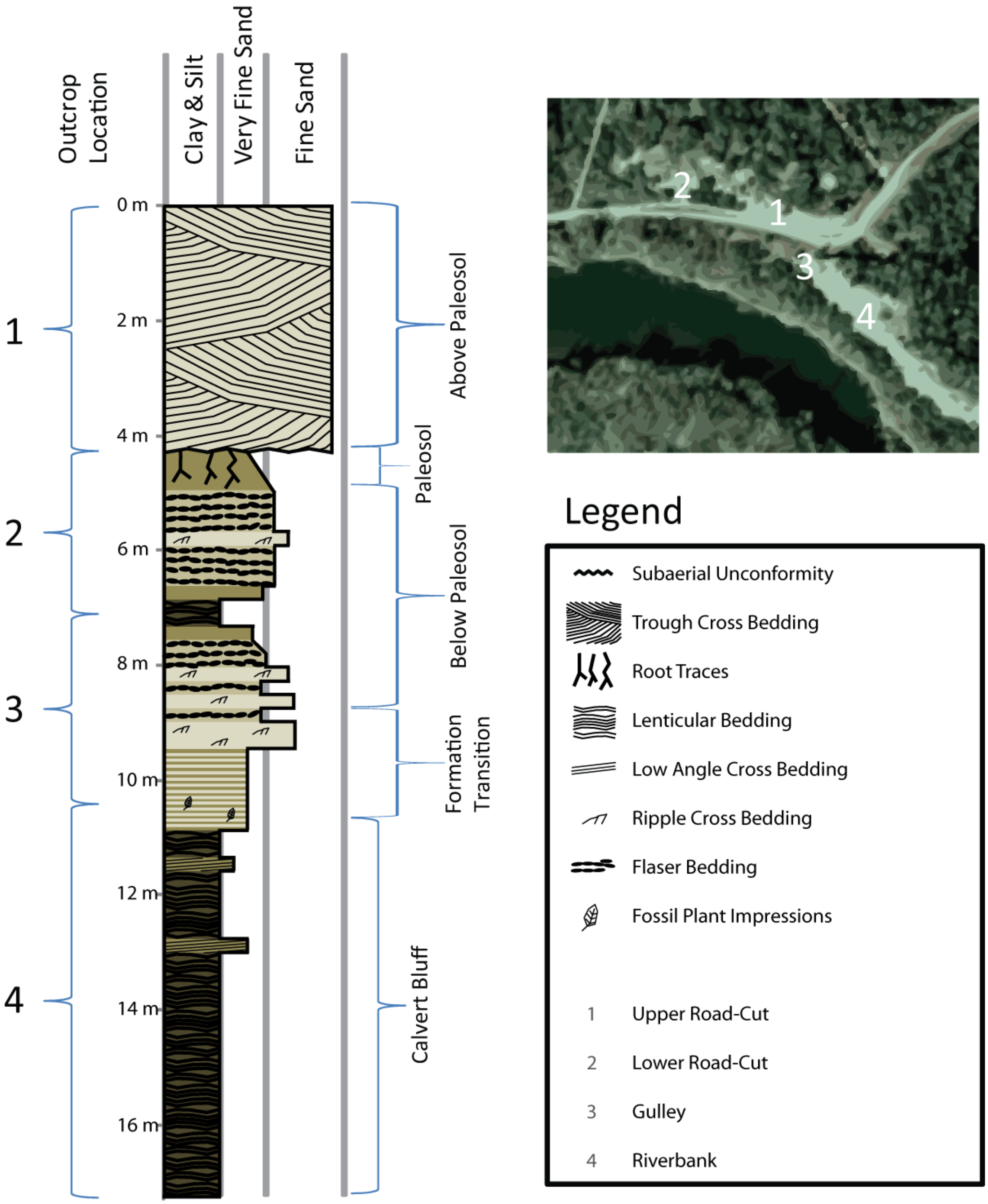


Fig 15: Composite section of outcrop descriptions from all four locations. Sedimentary features, the subaerial unconformity, color, and approximate grain size are shown.

Described Section

The section shown in Figure 15 was created from outcrop descriptions at four different locations in Bastrop, Texas. These locations are referred to as the upper road-cut (1), lower road-cut (2), gulley (3), and riverbank (4). Correlation between these locations was possible due to marker beds and surfaces at multiple sites. The riverbank and gully both contain the Calvert Bluff and Carrizo formation transition. The gully and lower road-cut both contain a distinct silt layer. The upper and lower road-cut locations both contain the same subaerial unconformity. Building a composite section from these locations enables the identification of several significant intervals. These intervals are referred to from bottom to top as the Calvert Bluff, formation transition, below paleosol, paleosol, and above paleosol intervals.

The Calvert Bluff interval at the bottom of the section consists of brown organic rich moderately sorted silts and clays with sand stringers and lenses as well as millimeter scale cross laminations. Other sedimentary features in the Calvert Bluff facies include thin sand beds with low angle cross bedding. The presence of a significant amount of gypsum was observed suggesting that the Calvert Bluff interval contained concentrations of pyrite from anoxic depositional conditions. The composition of the Calvert Bluff indicates that during deposition there was enough energy in the system to move available sediment. Possible depositional environments for the Calvert Bluff interval include bays, delta fronts or other shallow marine settings below wave base where low energy levels prevented the accumulation of significant quantities of sand. The characteristics of the Calvert Bluff interval indicate that it could be an excellent source or seal.

The formation transition interval is at the lithological contact between the Calvert Bluff formation and the Carrizo formation. The contact is gradational in that it can be characterized by sand and silt interbeds which shift from predominately silt to predominately sand. These interbeds contain terrestrial plant fossils and wavy bedding. Sedimentary features indicate increasing energy and coarser sediments. Permeability in this section could be poor due large quantities of silt and small amounts of producible sand.

The below paleosol interval consists of alternating sand and silt with indications of soft sediment deformation, cross bedding, ripples, and flaser bedding. Both the interbedding and sedimentary structures are cyclic. This indicates that energy levels were fluctuating allowing for the deposition of sands and silts. Based on sedimentary structures and stacking patterns possible depositional environments include tidal deltas, tidal flats, or estuaries. Permeability in the below paleosol interval appears to have significant lateral and vertical variation. Increased amounts of sand indicate that reservoir properties of the below paleosol interval are significantly better than those of the formation transition interval.

The paleosol lie directly below a distinct unconformity and is best described as poorly sorted fining upwards sediment with blocky characteristics and root traces. These characteristics are a result of sediment alteration during exposure. The original sediments were similar to the below paleosol interval. The outcrop unconformity corresponds with the regional basal Carrizo unconformity. Channel incision equivalent to this unconformity can be seen at another location at the Bastrop outcrop. Poor sorting beneath the unconformity indicates that the paleosol would be a poor reservoir and is probably a barrier to fluid flow.

The above paleosol interval is well sorted upper fine friable quartz sandstone with cross bedding. The lack of other fluvial sedimentary structures and the scale of the cross bedding indicates that this interval was deposited in a wave dominated shoreface setting where wave energy was the primary influence on sedimentary structures. The above paleosol interval is part of the Carrizo formation that serves as a regional aquifer in shallower settings. At depth, similar sediments have the capacity to store hydrocarbons due to the excellent sorting, permeability and porosity.

A stratigraphic sequence interpretation of the outcrop reveals one significant surface, the basal Carrizo unconformity, separating a basal highstand system tract from the overlaying transgressive system tract. There are two primary approaches to delineating stratigraphic sequences. One uses exposure surfaces and unconformities for sequence boundaries. This methodology suggests that two sequences are exposed in the outcrop. The lower sequence consists of an exposed highstand system tract containing the Calvert Bluff, formation transition, below paleosol, and paleosol intervals. The upper sequence consists of a transgressive system tract containing the above paleosol interval. For the rest of this study maximum flooding surfaces are used as sequence boundaries as indicated in previous work by Galloway (Galloway, et al., 1994; Galloway, et al., 2000). This is useful in the subsurface where the Upper, Middle, and Lower Wilcox are defined and bounded by flooding surfaces. This stratigraphic pattern and the previously described intervals assisted in identifying similar lithologies and depositional facies in the subsurface.

Grain Size Analysis

Figure 16 shows representative images of the above paleosol, paleosol, below paleosol, and Calvert Bluff intervals along with the mean grain size curve for the composite section as determined using the laser diffraction grain size analysis. Sediments in the Calvert Bluff interval between 10m and 18m from the top of the section have mean grain sizes ranging from 25 to 100 microns due to the predominance of silt with very thin sand lenses and lamina. The overall mean grain size for this interval is in the coarse silt range. The formation transition interval is between 8.8m and 10m from the top of the section and coarsens upwards as the mean grain size shifts from coarse silt and very fine sand to the fine sand range. Mean grain sizes in the below paleosol interval range from 50 microns to 175 microns. The subaerial unconformity is represented by a substantial change in mean grain size seen at 4.2m. The paleosol interval is a fining upwards section just beneath the subaerial unconformity. The above paleosol interval is represented by consistent measurements of average grain size between 160 and 200 microns in the upper fine sand range. These analyses of grain size and composition enable the creation of a quantitative lithology curve that can be compared to subsurface gamma ray and spontaneous potential logs for correlations and subsurface facies determination.

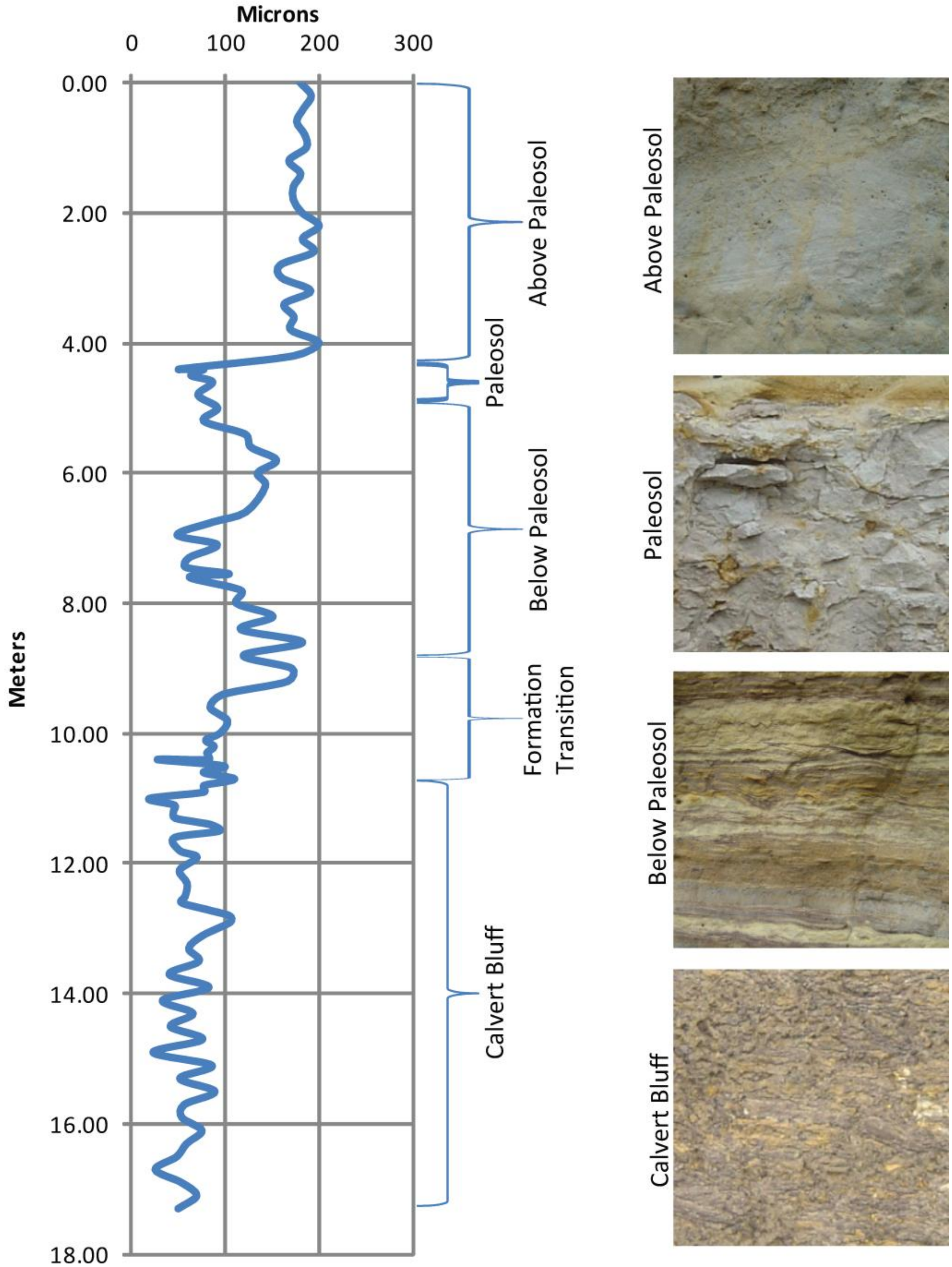


Fig 16: Mean grain size depiction (left) and four interval images (right). The top and basal facies have consistent grain sizes while the other facies are fining upwards, cyclic, or coarsening upwards.

Malvern grain size analysis provides grain size distributions and sorting for each sample. From this information one can group samples into similar intervals and observe general grain size patterns and characteristics. Figure 17 shows grain size distribution curves from each of the observed intervals as well as grain sorting. Each distribution chart shows the percentage of the sample that falls within a particular grain size range in microns. The Calvert Bluff samples are very poorly sorted with primary modes between 40 microns and 100 microns. There are two types of secondary modes in the Calvert Bluff. Those located between 4 and 10 microns indicate the inclusion of greater clay fractions. Those above 200 microns are the result of remaining silt aggregates in addition to small quantities of sand. Samples that were sieved through a 420 micron screen confirmed that the secondary modes near 500 microns were composed of silt grains that failed to disaggregate with HCl and H_2O_2 treatments. Grain size distribution curves from the formation transition zone show very poor sorting with samples composed of either very fine sand or silt. The below paleosol interval is poorly sorted with modes between 100 and 200 microns and some modes less than 70 microns. The paleosol is also very poorly sorted with broad grain size distributions that include significant percentages of silt and clay despite a primary mode near 100 microns. The above paleosol interval is moderately sorted and consistent throughout the measured section with grain size modes around 200 microns. These above paleosol samples also show evidence of grains in the 0.5 to 40 micron range.

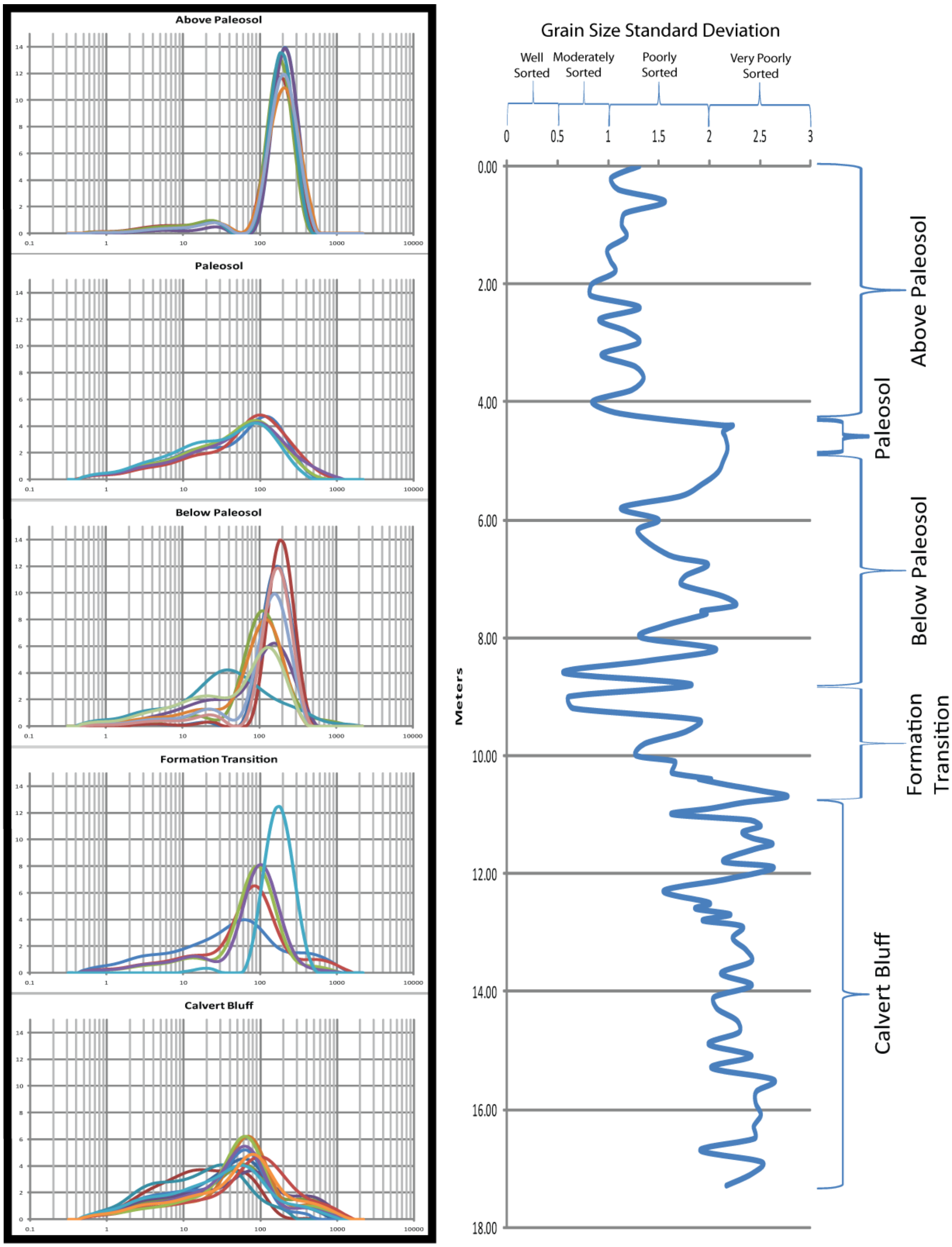


Fig 17: Interval grain size distributions (left) and grain sorting (right).

The correlation of the outcrop to the subsurface is illustrated in Figure 18. Shale content from a well approximately 31,000 ft away is compared to grain size data that has been stretched to 2.25 times its original thickness. Correlation of the original mean grain size curve is possible due to the similar log pattern, but the facies have increased in thickness at the well location. To compensate for this increased thickness the mean grain size curve was stretched. Confirmation of the correlation was achieved by cross plotting the outcrop mean grain size curve with Well A shale content. The results in Figure 18 indicate that grain sizes above 130 microns have similar gamma ray responses while finer grain sizes show the expected linear trend with increasing gamma ray responses for smaller grain sizes. Scatter in the cross plot for the very fine sand and silt samples is due to variations in organic content. The general facies identified in outcrop can also be observed in well logs. The above paleosol interval has a consistently low gamma ray response while the paleosol, below paleosol, and formation transition are expressed by cyclic responses. The Calvert Bluff interval has high gamma ray responses with greater variation than the grain size curve suggesting the presence of varying amounts of radioactive isotopes.

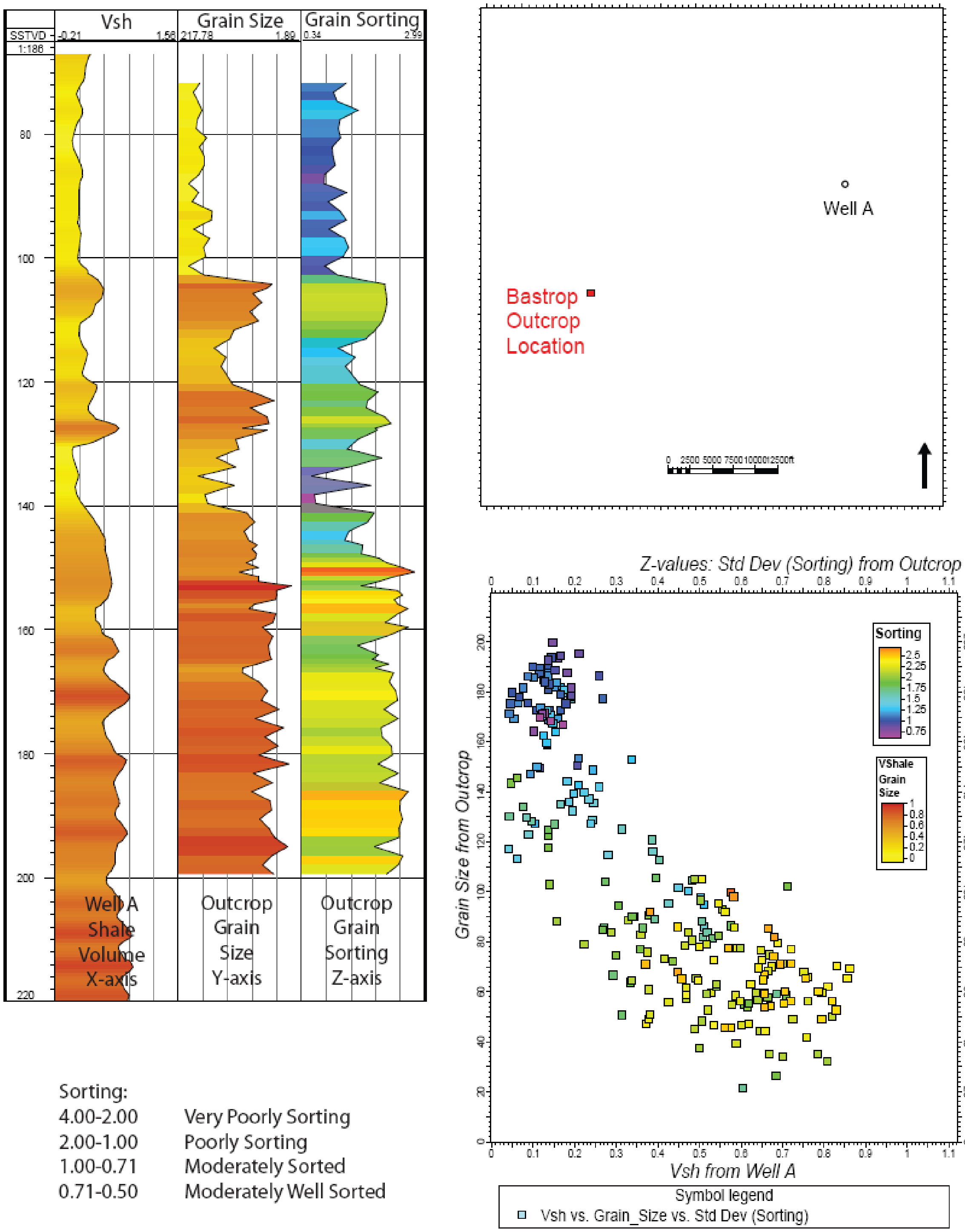


Fig 18: Correlation connecting the outcrop analog with Well A. Well A shale percent from gamma ray was cross plotted with outcrop mean grain size.

From the laser diffraction grain size data one can understand the porosity and permeability trend of the outcrop facies. This analysis compares the above paleosol interval and below paleosol interval, as they represent the only two potentially viable reservoir sands exposed in outcrop. Porosity values tend to vary according to grain sorting while permeability varies with both grain sorting and grain size. Therefore, the above paleosol interval is preferred over the below paleosol interval due to better grain sorting and larger mean grain sizes.

Conclusion

Several geologic insights obtained from this analog study can be applied to the Upper Wilcox reservoir interval. These insights pertain to grain size analysis, sedimentary structures, and stratigraphic interpretations. Correlation of these interpretations is valid since the exposed Carrizo and Calvert Bluff formations are members of the Upper Wilcox as defined by Galloway (Galloway, et al., 2000). Identified highstand and transgressive deposits in the Upper Wilcox should reflect patterns that are consistent with the outcrop interpretation. Another analogous feature is that the reservoir intervals and outcrop both have the same sediment supply and source (Harris, 1962; Hutto, et al., 2009). Other aspects considered include the possibility that sands within the formation might have significantly different reservoir characteristics. However, it was difficult to determine these differences with only subsurface well logs, as evidenced when comparing the above paleosol and below paleosol mean grain size curves. The depositional characteristics or mode for the outcrop hold for the study area. Geologic characteristics derived from the outcrop analog analysis compare favorably with data from the Upper Wilcox despite a significant distance separating the two locations.

CHAPTER V

UPPER WILCOX RESERVOIR HETEROGENEITY MODEL

Introduction

Enhanced seismic in conjunction with outcrop analog analysis, well log data, and conventional seismic can substantially improve reservoir heterogeneity models. This chapter uses the methodology developed in this study to compare models generated from the conventional seismic and from the enhanced seismic data. Through the interpretation of an Upper Wilcox reservoir interval located between 8220ft and 8545ft subsea depth in Well 4, it is found that enhanced seismic images reservoir connectivity and heterogeneity with greater resolution and accuracy than conventional seismic.

Analog Application

Potential reservoir intervals associated with the outcrop analog analysis were identified by comparing well log facies with outcrop grain size variations and stratigraphic correlation from the outcrop to the study area. Figure 19 shows a regional stratigraphic cross section hung on the Middle Wilcox marker with the top and base of the Wilcox indicated along with the approximate location of facies analogous with the outcrop. Surfaces marked were selected based on work compiled by William Galloway and are consistent with regional stratigraphic interpretations (Galloway, et al., 1994). Regional detachment of the Wilcox Group on the basinward side of the Stewart City Cretaceous Shelf Margin is responsible for the significant thickening of Wilcox sediments between wells G and 4 as well as creation of large normal faults as observed in seismic. Since the thickness between the outcrop facies and top of the Wilcox remains constant over the same interval, one can use the outcrop analog without accounting for significant syn-depositional fault movement.

Well Log Analysis

Petrophysical analysis consisted of determining shale content, water saturation, and porosity in Well 4. Net pay was defined as rock with shale content less than 60%, water saturations less than 50%, and porosities greater than 10%. The outcrop analog facies match log facies in the lower part of the reservoir interval from 8475ft to 8545ft. Figure 20 illustrates this formation evaluation along with density neutron crossover indicating that natural gas is the dominate type of hydrocarbon present.

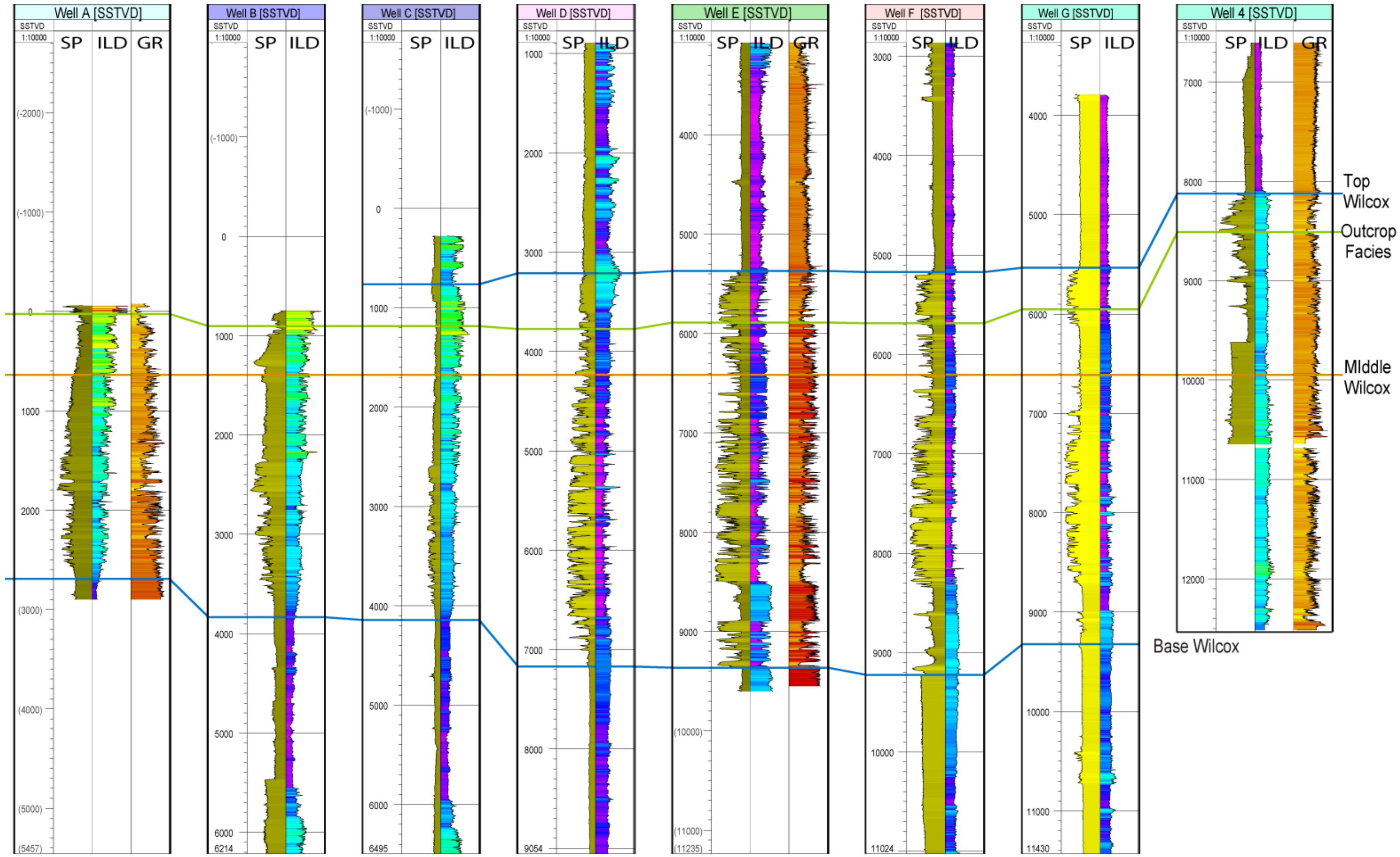


Fig 19: Regional cross section connecting the outcrop analog with the study area. Wells A-G and Well 4 were used for the correlation with the top Wilcox, Middle Wilcox, base Wilcox, and analogous facies marked. The correlation is hung on the Middle Wilcox.

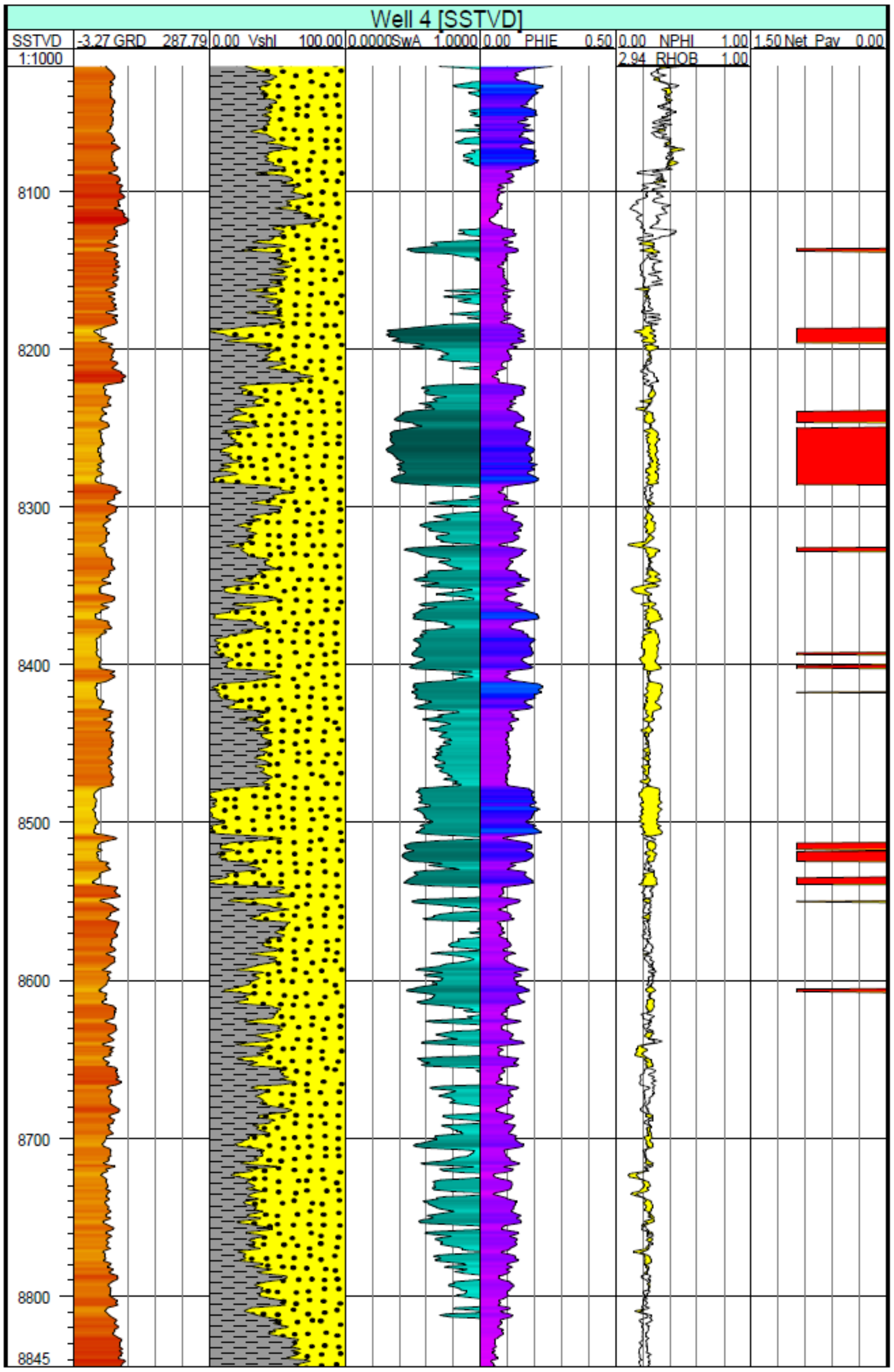
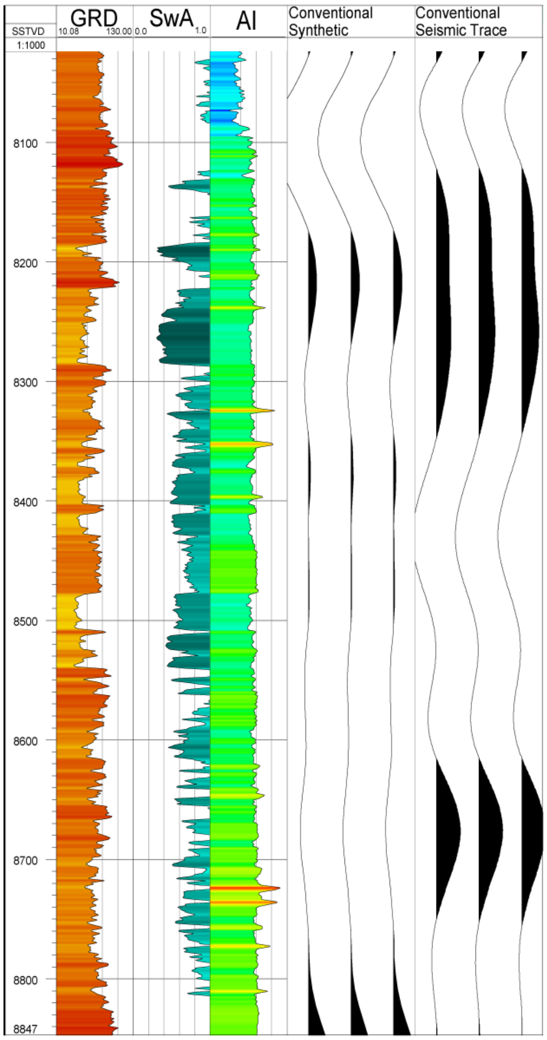


Fig 20: Formation evaluation of the Upper Wilcox reservoir interval. Logs displayed from left to right are gamma ray, shale content, water saturation, porosity, neutron density porosity crossover, and net pay.

Synthetic Seismogram Analysis

The synthetic seismograms and extracted seismic traces from the conventional seismic volume are shown in Figure 21. Identifiable features in this synthetic seismogram includes the trough associated with the top of the Wilcox due to a sudden density and velocity increases. The increase in acoustic impedance marks an important stratigraphic surface that is expressed as a trough instead of a peak due to the phase of the seismic waveform. It should also be noted that individual sands or potential reservoir intervals were not visible due to poor resolution in the conventional seismic. The conventional dominate frequency of 16Hz yields wavelengths on the order of 650ft. The smallest bed where both the top and base can be identified would be about 162ft thick. The smallest visible bed would be approximately 81ft thick. Consequently, individual reservoir sands cannot be delineated with conventional seismic. The surface used to map the reservoir was the peak-trough zero crossing at 8340ft subsea depth.

The Upper Wilcox enhanced synthetic seismogram located on the right side of Figure 21 shows significantly higher resolutions and more visible layers. It is important to note that the same trough at the top of the Wilcox is clearly identifiable on both conventional and enhanced seismic. Thin layers of reservoir sands can also be identified on the enhanced seismic. The resolution of enhanced seismic for this interval is dependent on a dominate frequency of 65Hz instead of 16Hz. The wavelength for the Upper Wilcox enhanced seismic is around 175ft enabling separable resolutions of 43ft and visible resolutions of 22ft. Since gas filled pore space tends to have large influences on amplitude, thin reservoir sands are identifiable on enhanced seismic data.



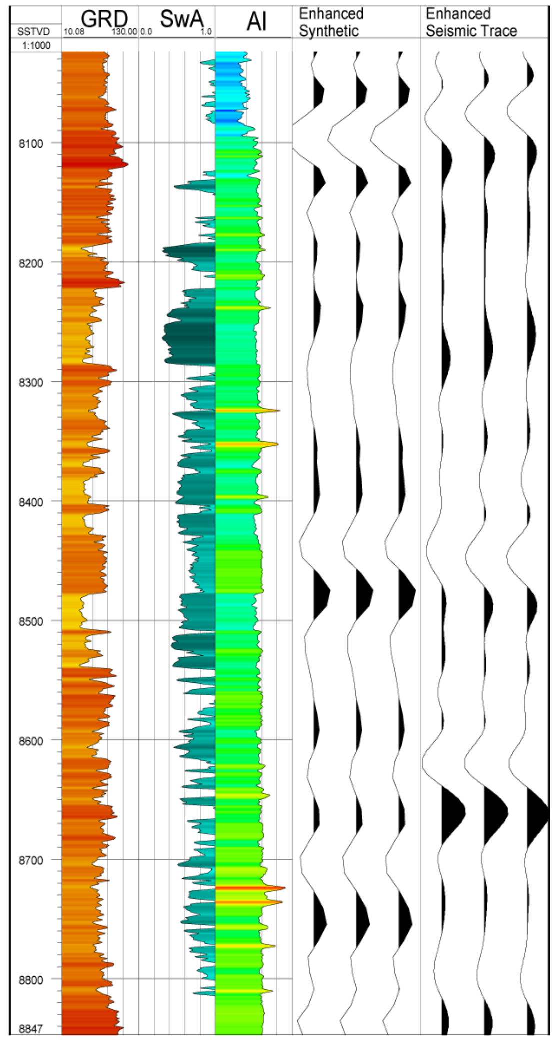


Fig 21: Conventional (left) and enhanced (right) synthetic seismograms in the Upper Wilcox reservoir interval. Tracks shown contain gamma ray, water saturation, acoustic impedance synthetic seismograms, and extracted seismic traces in that order.

Conventional Seismic Analysis

Conventional seismic interpretation of the Upper Wilcox reservoir interval consisted of delineation of large faults and regional structure for the reservoir. Conventional interpretation and coherency analysis indicate two major faults intersect the reservoir interval. A blind fault is responsible for the monocline across the middle of the seismic survey. All three faults trend to the northeast with the blind fault bisecting the seismic survey while the other major faults are located along the southeastern edge of the study area. Based on the structure map shown in Figure 22, the coherency time slice shown in Figure 23, and the thickness of the reservoir, the blind fault should not affect fluid flow unlike the two major faults along the southeastern edge of the seismic survey. Of these two major faults, the offset of the smaller fault might permit fluid flow while the larger fault is most likely a lateral seal. Consequently, the seismic survey contains only the top and southeastern seals. Not all of the lateral traps are visible in seismic, but the structural regime and hydrocarbon charge indicate the presence of effective lateral seals.

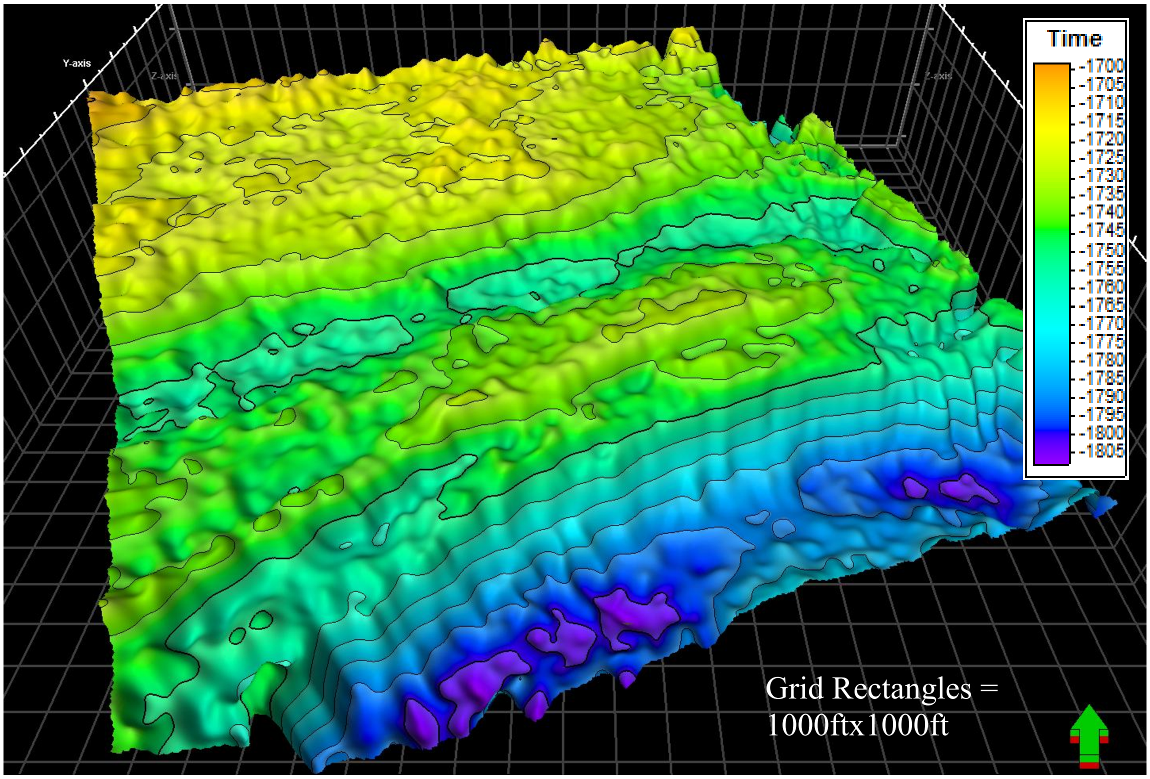


Fig 22: Conventional seismic Upper Wilcox reservoir structure map. Two faults are visible and the monocline is caused by a blind fault.

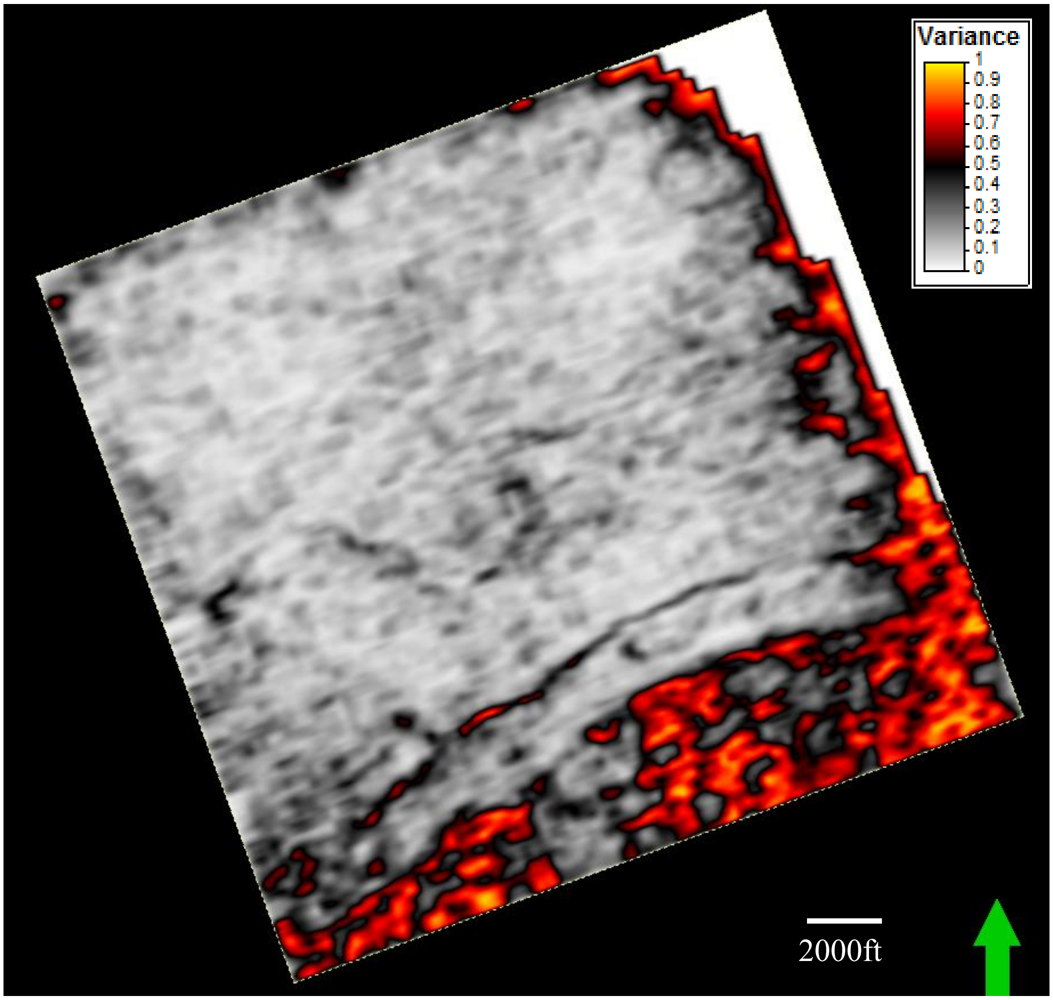


Fig 23: Conventional seismic coherency attribute time slice at 1700ms. Two faults to the southeast intersect the Upper Wilcox reservoir interval. The darker region through the center of the survey is near the blind fault.

Enhanced Seismic Analysis

Structural interpretation of the enhanced seismic reflections associated with this Upper Wilcox interval are consistent with the surface mapped with the conventional seismic. Secondary faulting is not present in much of the reservoir interval. This indicates that the small-scale structural characteristics identifiable in the enhanced seismic may not significantly influence fluid flow while larger-scale faults segment the reservoir interval. Figure 24 shows both the conventional and enhanced seismic along the faulted southeastern half of the seismic survey

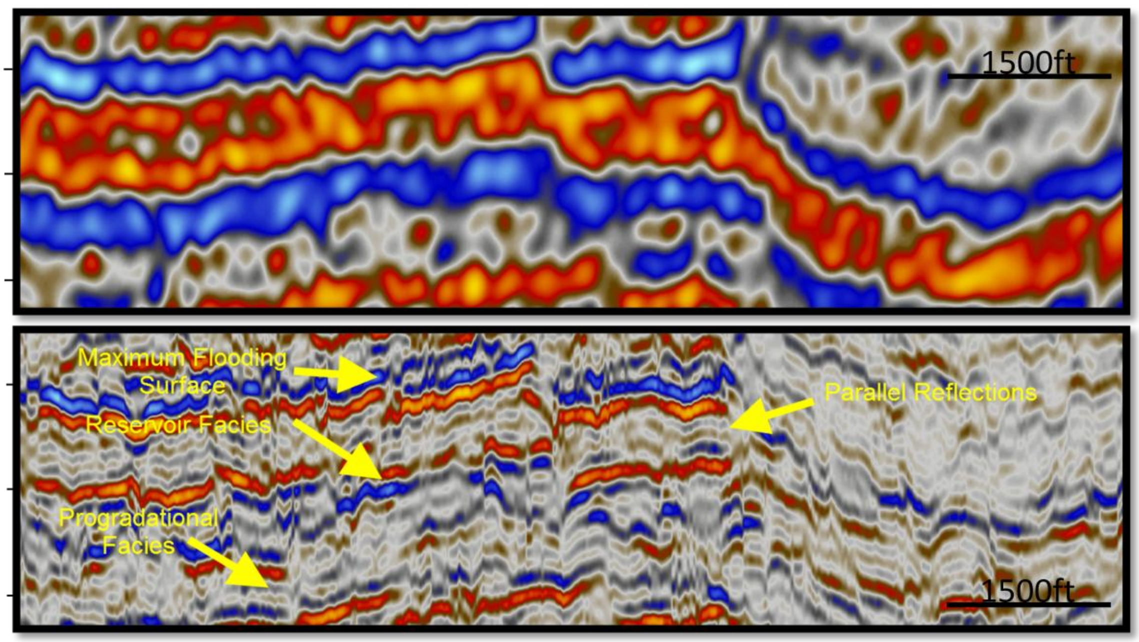


Fig 24: Structural interpretation of enhanced seismic for the Upper Wilcox (bottom). Inline 1015 compares enhanced seismic facies, faults, and stratigraphic surfaces with conventional seismic (top).

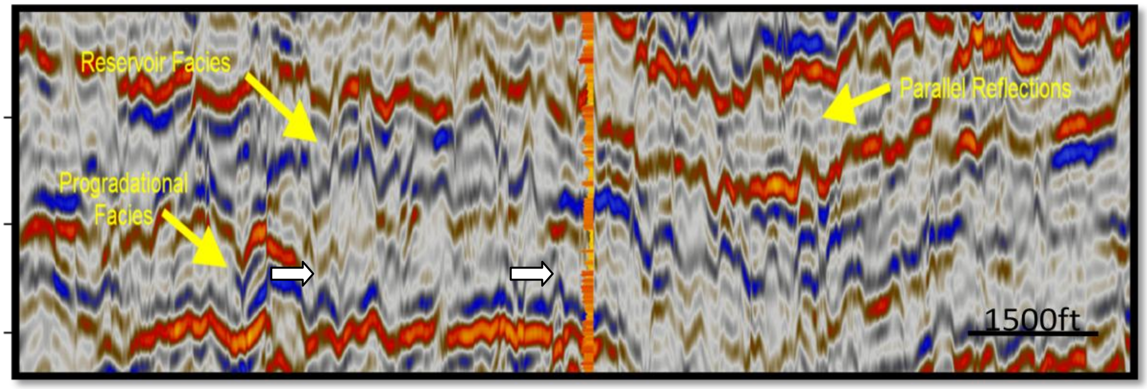


Fig 25: Facies interpretation of enhanced seismic for the Upper Wilcox. Inline 1015 illustrates a progradational seismic facies beneath the reservoir and parallel seismic reflections above the reservoir. Well 4 is included for comparing log scale features with enhanced seismic. White arrows indicate onlap or downlap.

Two distinct seismic facies are visible above and below the Upper Wilcox reservoir interval. Above the Upper Wilcox reservoir interval are parallel reflections with few indications of lateral variation. Beneath the Upper Wilcox reservoir interval are progradational packages as illustrated in Figure 25. The parallel reflections above and progradational packages below the Upper Wilcox reservoir interval suggest that the reservoir might be a transgressive sheet sand deposited over a delta before burial by marine sediments. Similar seismic facies analysis can be performed on flattened seismic as shown in Figure 26 were the downlaping facies, reservoir facies, and overlaying facies are clearly visualized.

Fluid effects on acoustic interfaces caused by natural gas in reservoir sands can be observed in this interval through the use of an envelope attribute volume as shown in Figure 27. The reservoir sheet sands are clearly identifiable and separable from lower progradational sands.

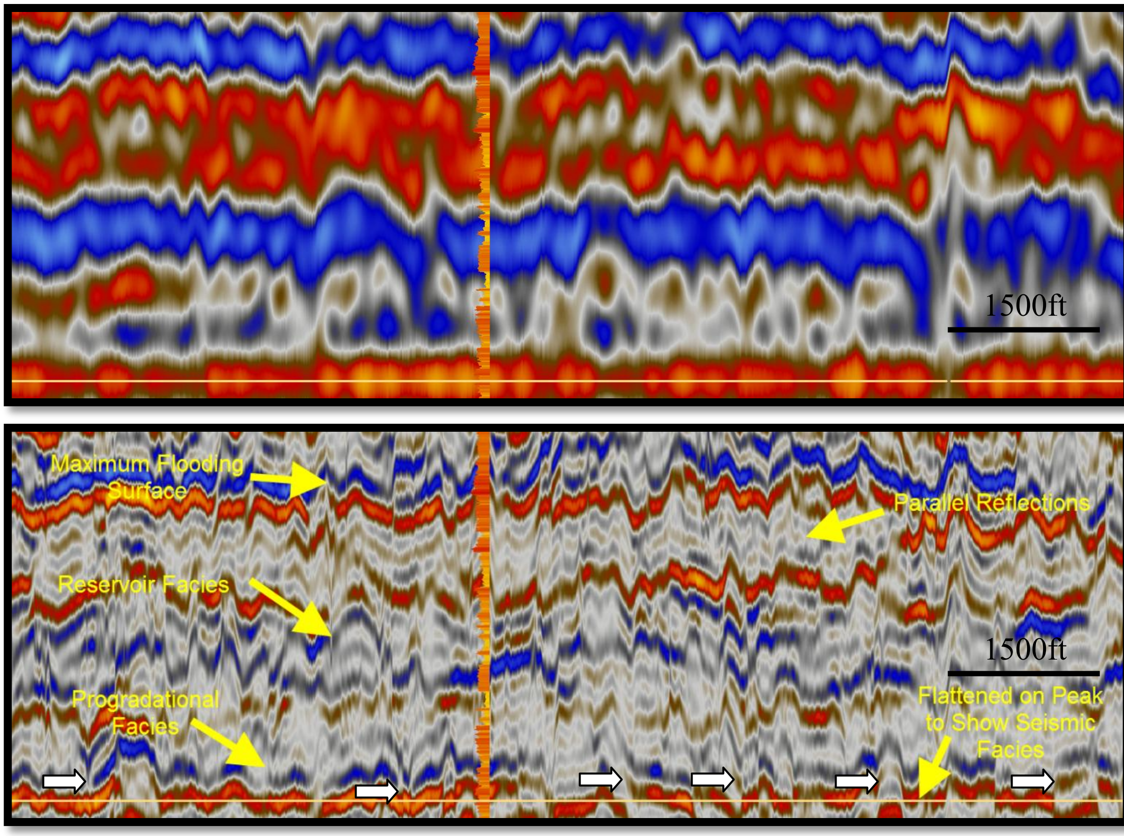


Fig 26: Upper Wilcox flattened enhanced seismic facies interpretation. In this case the seismic is flattened on the conventional seismic peak that corresponds with downlap in the enhanced seismic.

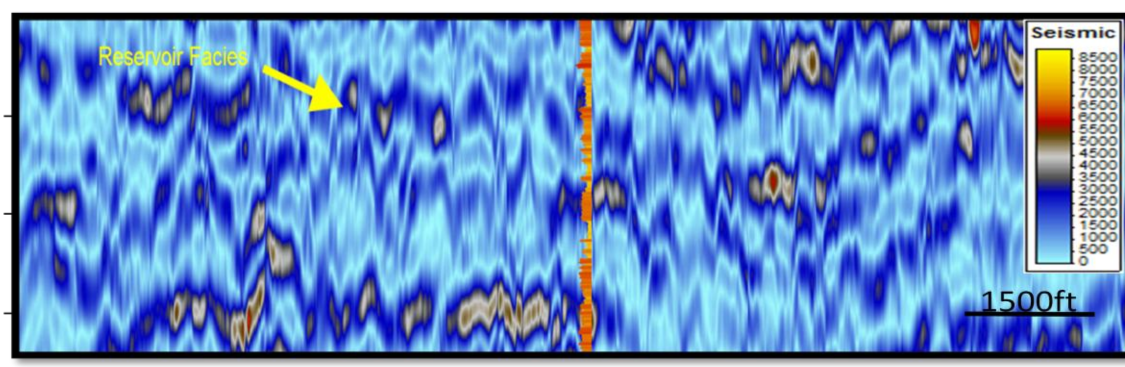


Fig 27: Upper Wilcox enhanced envelope attribute along inline 1015. Bright spots along the reservoir facies are caused by hydrocarbon fluid effects. Bright regions above the reservoir correlate with a maximum flooding surface. Below the reservoir bright regions are related to fluid effects.

Reservoir Connectivity and Heterogeneity Analysis

Reservoir heterogeneity for the Upper Wilcox reservoir interval was determined by compiling all of the relevant results of individual analysis from each type of geological and geophysical datasets. This analysis indicated that the reservoir in question is a sheet sand intersected by secondary faults. Reservoir characteristics from petrophysical evaluation show that the upper clean sand is porous and charged with hydrocarbons. Analysis of the outcrop analog indicates that the transgressive facies is most likely a clean sand. Seals are marine shales, and trapping mechanisms are related to the large and easily identifiable normal faults. These observations place into context further analysis of reservoir interval connectivity.

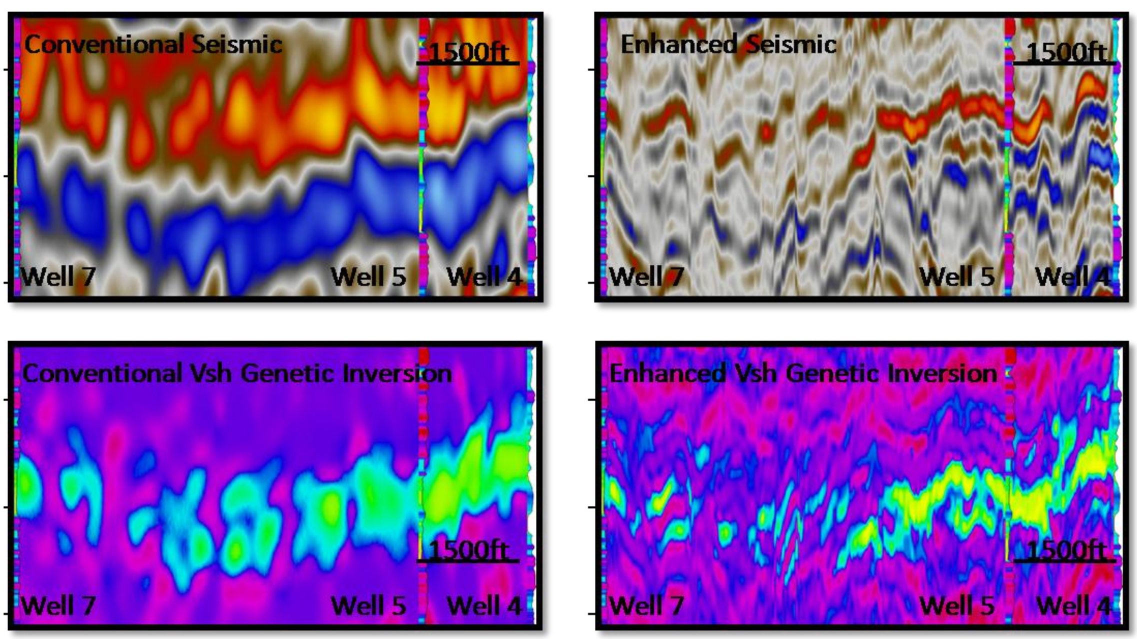


Fig 28: Shale content genetic inversion volume comparison. Conventional (top right) and enhanced seismic (top left) compared with conventional (bottom right) and enhanced (bottom left) shale content genetic inversions on an arbitrary line connecting wells, 4, 5, and 7.

Connectivity analysis on the Upper Wilcox reservoir interval involved using a genetic inversion of the shale content from both the conventional and enhanced seismic integrated with petrophysical evaluation of Wells 4, 5, 7, and 8 (Figure 28). For this inversion the spontaneous potential log was used to calculate shale content at the well locations and special care was made to match synthetic seismograms from each well with enhanced seismic traces. This permitted the clear identification of the reservoir interval as a sheet sand after the inversion. Comparison of the conventional and enhanced shale content genetic inversions reveals a significant increase in detail from the seismic enhancement as shown in Figure 29. This comparison demonstrates the advantage of resolution improvements in enhanced seismic over conventional seismic data for reservoir characterization.

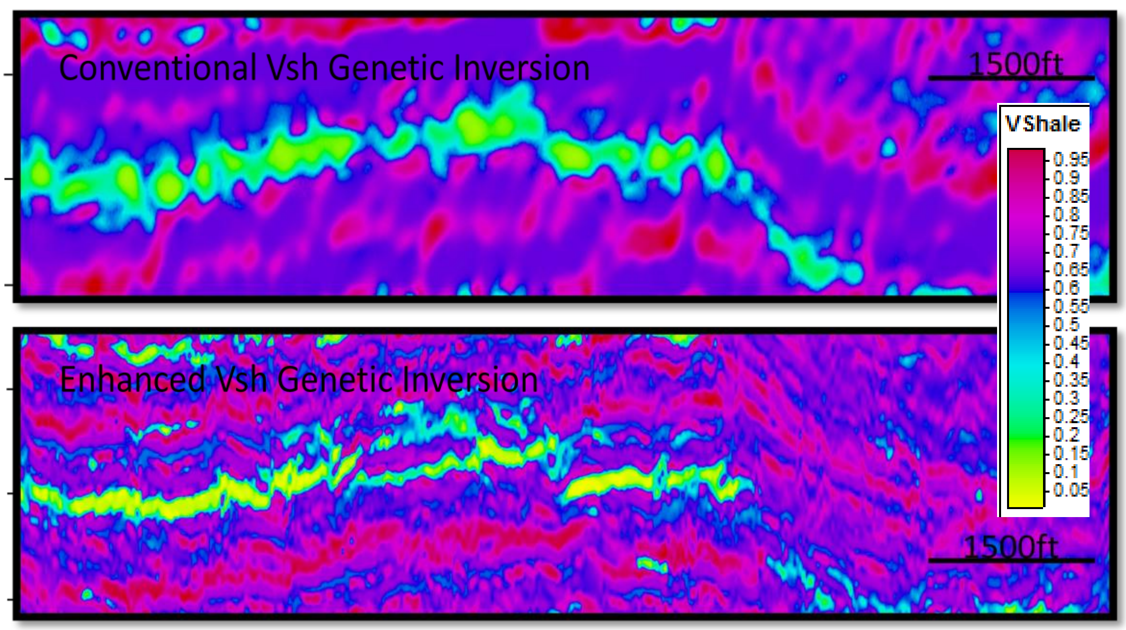


Fig 29: Shale content genetic inversions for the Upper Wilcox. Sands are indicated in the green and yellow.

Geobody extraction from both the conventional and enhanced genetic inversion volumes was performed for connected sands that had shale content of less than 45%. Both the conventional and enhanced seismic reflected the reservoir interval as a sheet sand as shown in Figures 30 and 31. The conventional seismic interpretation shows reservoir sand communication on either side of the largest fault while not connecting them on the southwestern side landward of the smaller fault. However, the enhanced interpretation treats the large fault as a lateral seal and connects thinner sand intervals in the southwestern side landward of the smaller fault. The enhanced interpretation is consistent with the regional geology while the conventional interpretation raises significant geologic concerns regarding accuracy and consistency.

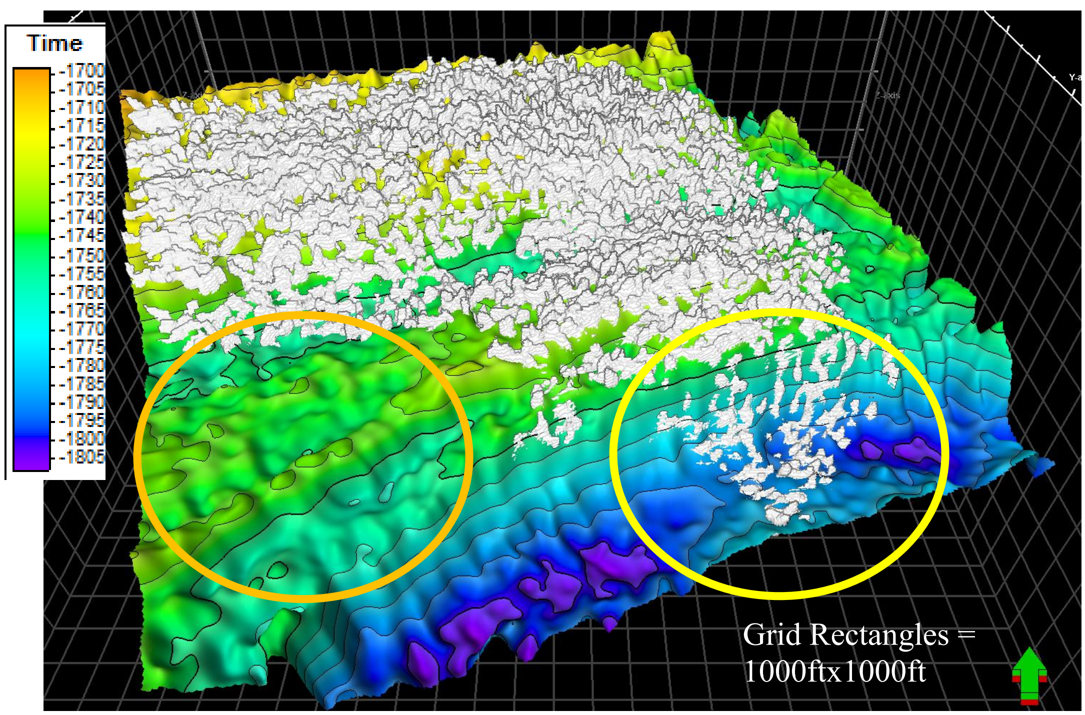


Fig 30: Conventional seismic Upper Wilcox reservoir geobody extraction. This geobody suggests a stratigraphic seal preventing migration into the orange circle while a large fault does not prevent migration into the yellow circle.

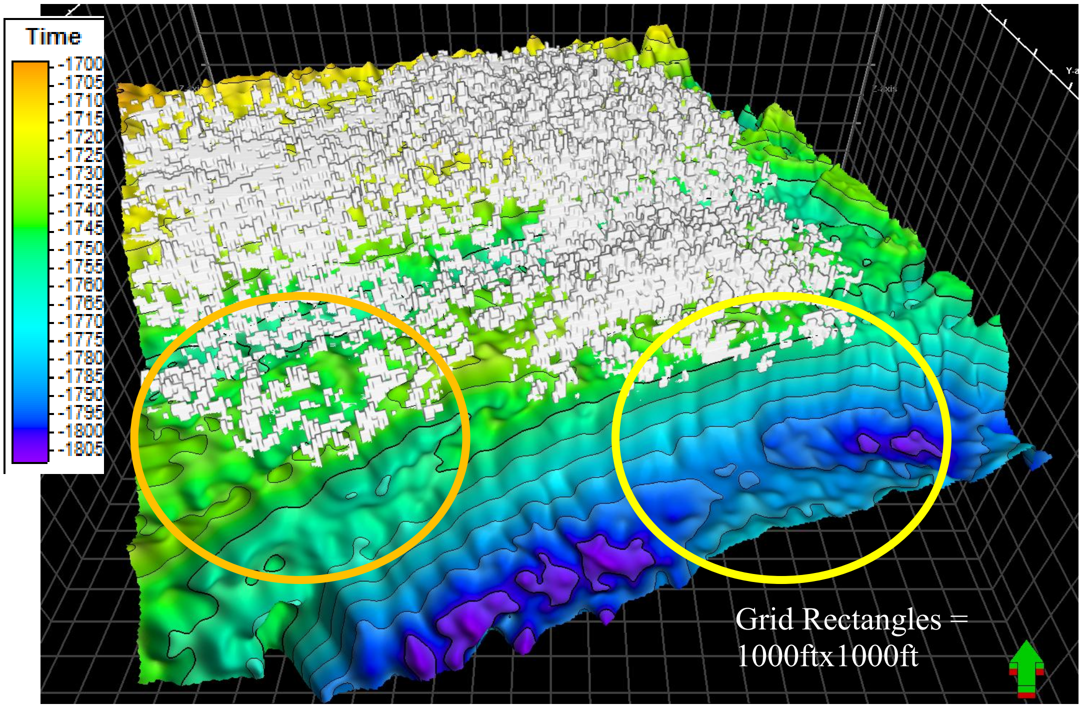


Fig 31: Enhanced seismic Upper Wilcox reservoir geobody extraction. This geobody suggests regional deposition with large faults trapping hydrocarbons in the yellow circle and thin reservoir sands in the orange circle.

Conclusion

Enhanced seismic and reservoir connectivity analysis revealed additional geologic features and reservoir characteristics not apparent when analyzing conventional seismic. These features and reservoir characteristics result in a more detailed stratigraphic interpretation of the reservoir architecture as well as a more accurate interpretation of communication between reservoir sands. The detailed stratigraphic interpretation from the enhanced seismic indicates that the reservoir sands have a relatively consistent thickness. Overlying sediments were deposited in a manner that produced parallel reflections while underlying sediments appear to indicate delta lobe progradation. This interpretation from enhanced seismic could not have been made with conventional seismic.

Comparisons of conventional seismic and enhanced seismic interpretations of reservoir connectivity in the Upper Wilcox demonstrate that the enhanced seismic significantly improves geologic consistency for geobody extraction. This has significant implications on exploration for bypassed hydrocarbons. The first implication relates to reliable identification of faults as either a migration pathways or seals. The second relates to resolving and mapping thin reservoir sands.

CHAPTER VI

UPPER MIDDLE WILCOX RESERVOIR HETEROGENEITY MODEL

Introduction

High-resolution structural and stratigraphic interpretation of enhanced seismic in conjunction with connectivity analysis can be used to map reservoir heterogeneities and determine reservoir quality. This chapter focuses the importance of stratigraphic effects on reservoir heterogeneity by creating depositional and reservoir models for the Upper Middle Wilcox interval. These models are then placed in a regional model in order to better understand deposition during this part of the Upper Middle Wilcox.

Well Log Analysis

Petrophysical analysis was performed for the Upper Middle Wilcox reservoir interval to determine shale content, water saturation, and porosity in Well 4 between 10300ft and 11150ft subsea depth. Net pay was defined as rock with shale content less than 60%, water saturations less than 50%, and porosities greater than 10%. Figure 32

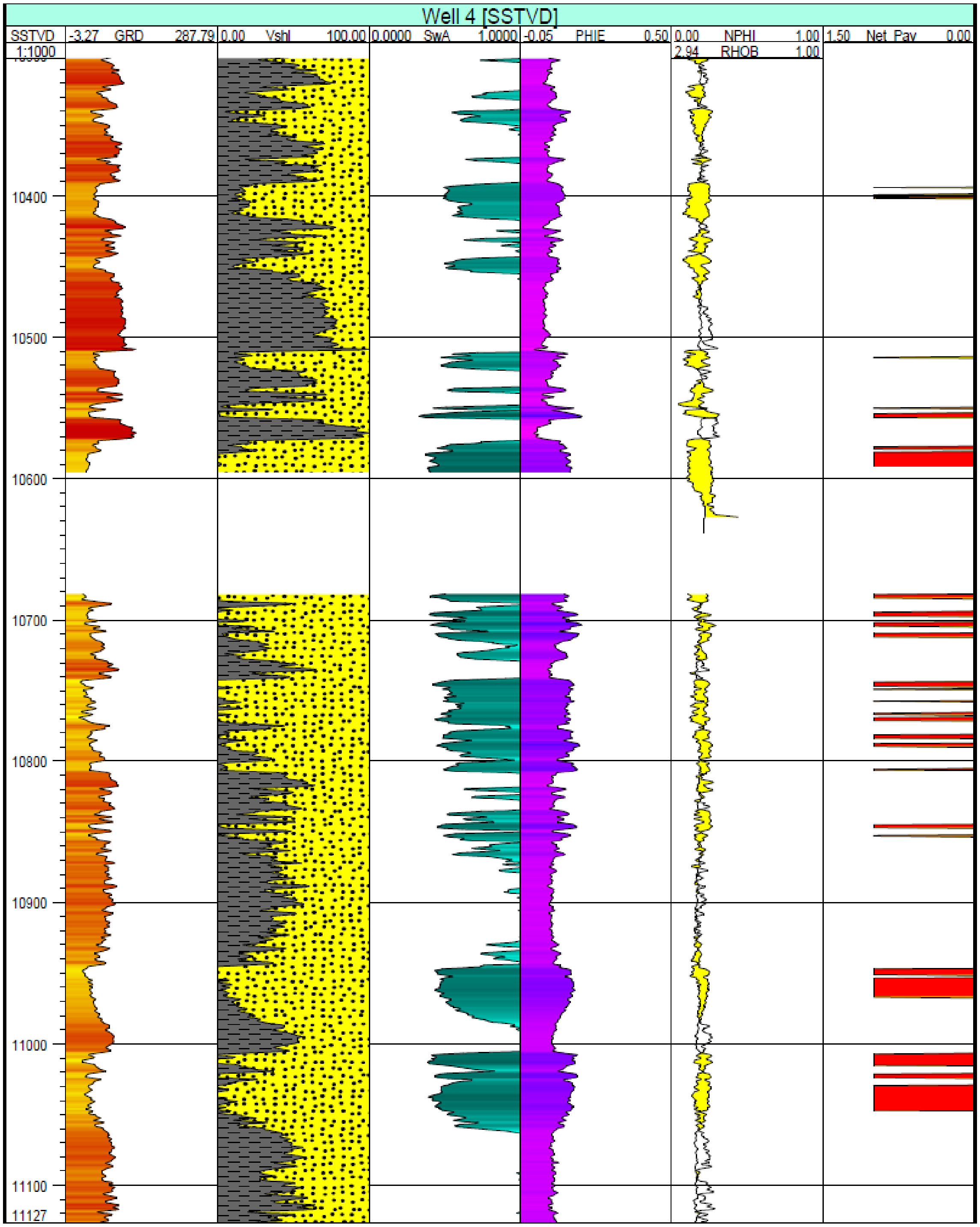


Fig 32: Formation evaluation of the Upper Middle Wilcox reservoir interval. Logs displayed from left to right are gamma ray, shale percent, water saturation, porosity, neutron density porosity crossover, and net pay.

shows the gamma ray, shale content, water saturation, porosity, neutron-density crossover, and net pay logs. Note the missing log data between 10600ft and 10675ft in Well 4. This missing log data does not affect enhanced seismic interpretation or generation of genetic inversion volumes due to the inclusion of multiple wells in the study area. The neutron density crossover and general pattern of the density log strongly suggest that the upper portions of the missing intervals are sands. Analysis of neighboring wells is consistent with this interpretation.

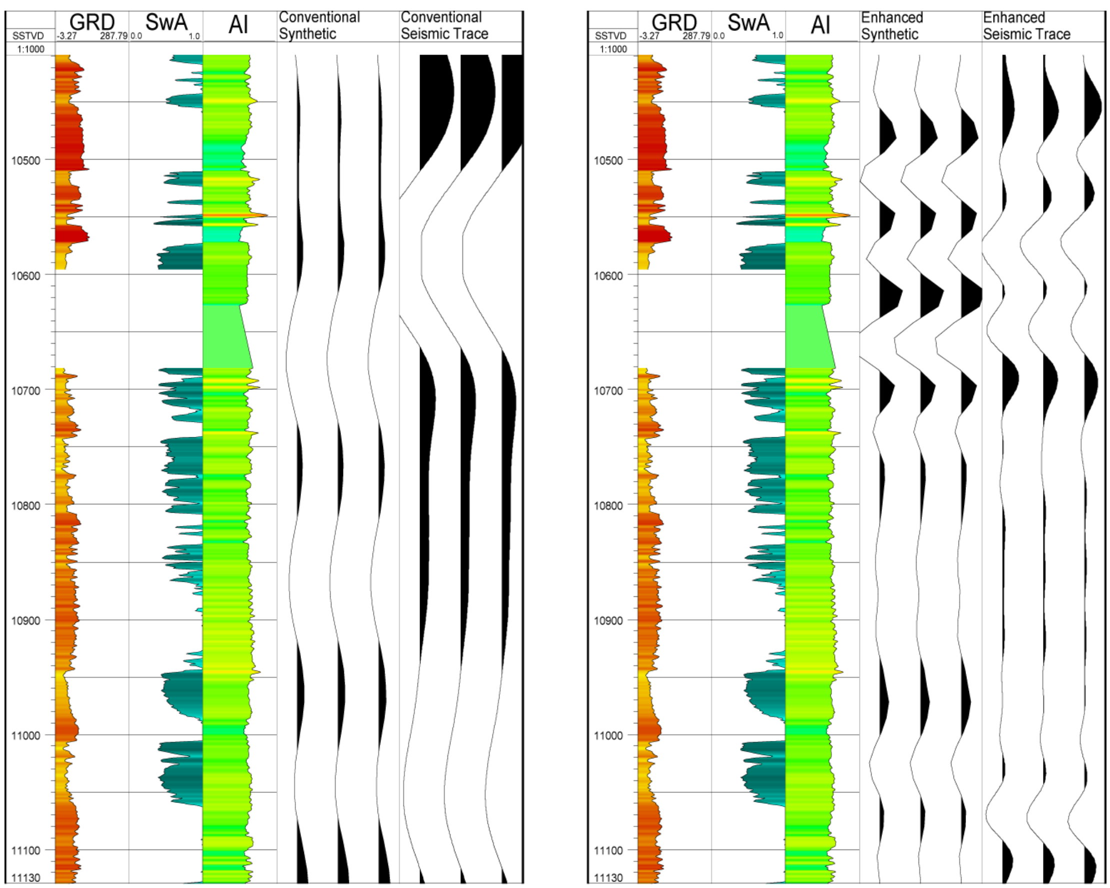


Fig 33: Conventional (left) and enhanced (right) synthetic seismograms in the Upper Middle Wilcox reservoir interval. Tracks shown contain gamma ray, water saturation, acoustic impedance synthetic seismograms, and extracted seismic traces in that order.

Synthetic Seismogram Analysis

The conventional synthetic seismogram located on the left side of Figure 33 depicts the synthetic seismogram and extracted conventional seismic traces along Well 4 for the Upper Middle Wilcox. Poor log data between 10600ft and 10675ft is responsible for both poor time-depth relationships and poor matches between the synthetic seismogram and extracted seismic traces. Despite this, it should be noted that a significant anomalous amplitude area is present in the seismic at the top of the reservoir interval. This might be due to fluid influences on seismic expression. Conventional seismic resolution in this region is limited by a dominate frequency of 16Hz and wavelength of around 690ft. It means that beds greater than 172ft thick should be separable and beds greater than 86ft thick should be visible.

The enhanced synthetic seismogram located on the right side of Figure 33 for the Upper Middle Wilcox reservoir interval shows significant error due to missing log data. Despite this some important features are still discernable. The first is that the upper sands can be traced in enhanced seismic as high amplitude peaks or troughs. The lower sands are not expressed as clearly in the enhanced seismic. Since shales and water-wet sands tend to have low seismic amplitudes, fluid effects are a significant factor in the interpretation of this enhanced seismic volume. The dominate frequency for the Upper Middle Wilcox enhanced seismic is 65Hz. Seismic wavelengths are 180ft permitting separable bed resolutions at 45ft and visible resolutions at 23ft. Since gas filled pores tend to have large influences on seismic amplitude, potentially productive thin reservoir sands should be visible in this seismic survey.

Conventional Seismic Analysis

Conventional seismic interpretation of this reservoir interval consists of the delineation of large-scale normal faults and regional structure for the reservoir interval. Conventional interpretation and coherency analysis show three large-scale faults intersecting the reservoir. One large-scale fault is situated along the northwestern edge and another large-scale fault is situated at the southeastern edge of the seismic survey. The third large-scale fault trends to the northeast and cuts the survey in half. Based on the structure map shown in Figure 34, the coherency time slice shown in Figure 35, and the thickness of the reservoir, all three of the large-scale faults are probably barriers to fluid flow. The anticlines created by these normal faults form structural traps for hydrocarbons. Therefore, conventional seismic can be used for mapping of the reservoir interval and identification of large-scale features.

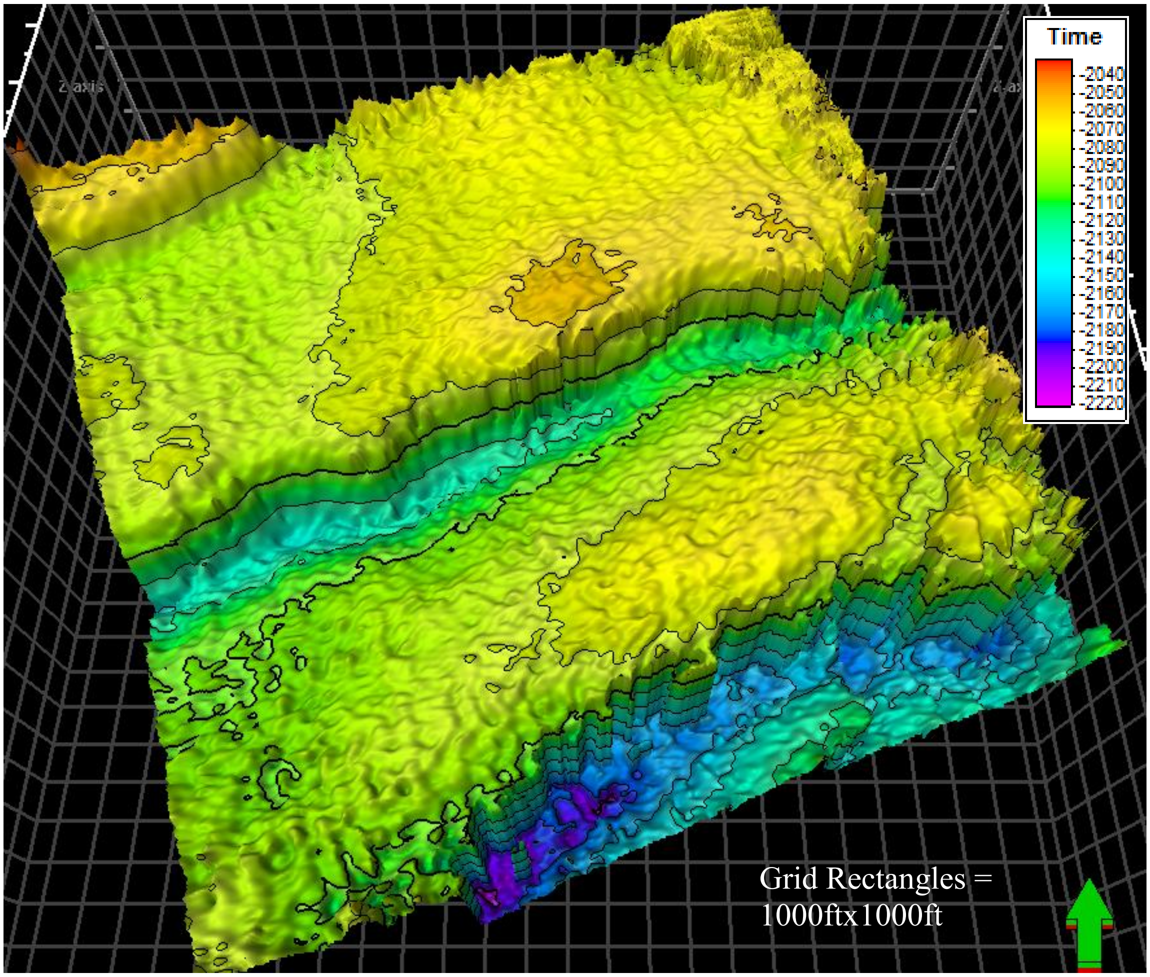


Fig 34: Conventional seismic Upper Middle Wilcox reservoir structure map. Two rollover anticlines and three distinct normal faults are shown.

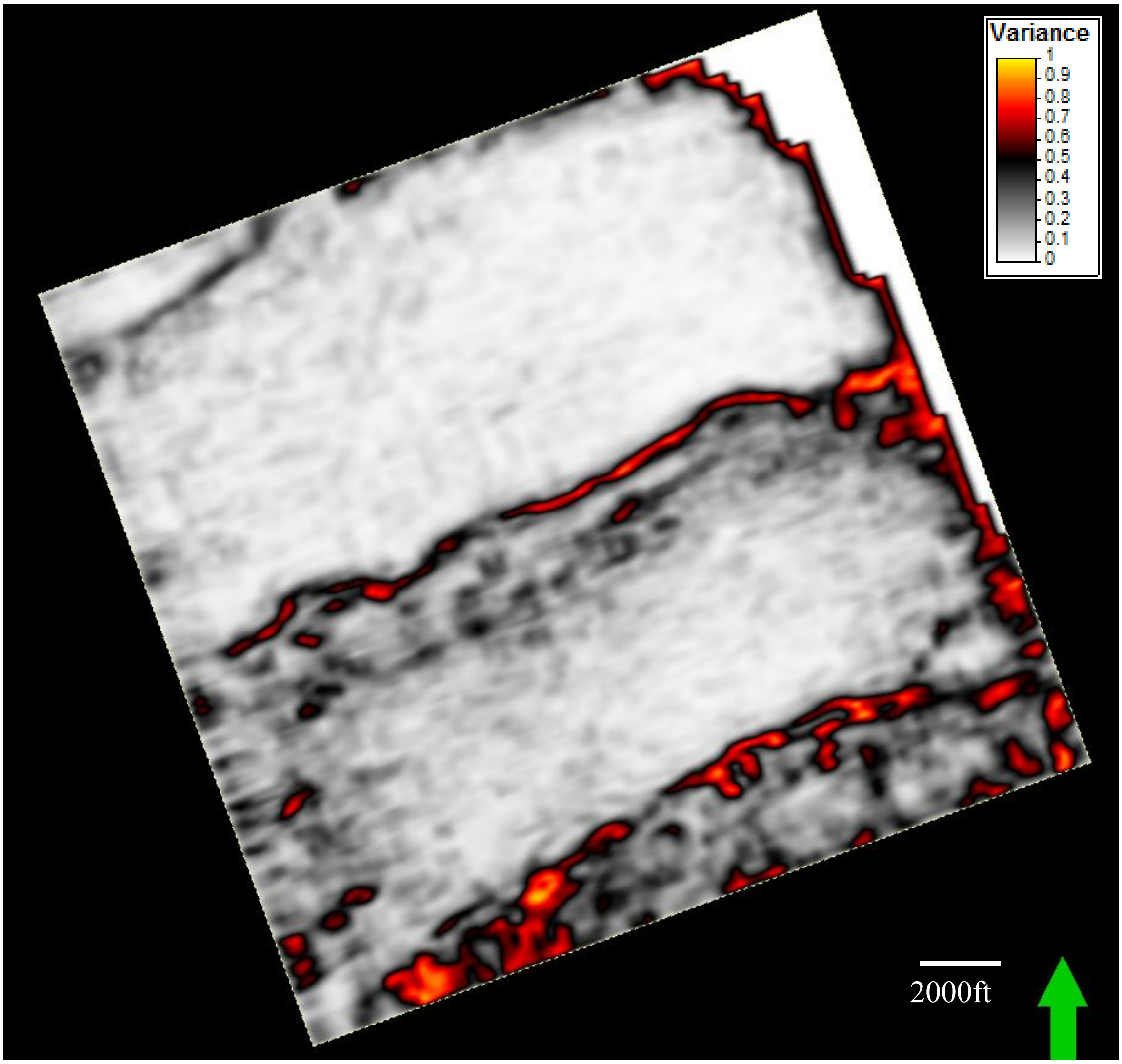


Fig 35: Conventional seismic coherency attribute time slice at 2060ms. Three major normal faults in the Upper Middle Wilcox reservoir interval are shown.

Enhanced Seismic Analysis

Interpretation of enhanced seismic focuses on fine-scale structure and stratigraphy that is not revealed with conventional seismic. Enhanced seismic structural interpretation detected the three large-scale faults and a significant number of secondary faults. It appears that these secondary faults do not have enough offset to segment the reservoir sands into separate flow units. Flattening of the seismic horizon representing the top of the reservoir interval indicates that the southeastern major fault was stationary during deposition of the Upper Middle Wilcox as indicated in Figure 36. Onlap and downlap of the reservoir facies onto the underlying seismic facies is also shown in Figure 36.

This seismic enhancement of the Upper Middle Wilcox reservoir interval enables interpretation of significant stratigraphic features. The seismic facies beneath the reservoir interval consists of low amplitude parallel reflections consistent with deposition of fine grained material in a marine setting. The reservoir seismic facies contains very high amplitude reflections that onlap and downlap the lower facies. Seismic facies above the reservoir have low amplitude parallel reflections. The reservoir facies illustrated in Figure 37 is consistent with lobate progradational sand deposition. Possible depositional systems for the Upper Middle Wilcox include gravity flows associated with slumping and instability after movement of large landward normal faults during rising sea levels.

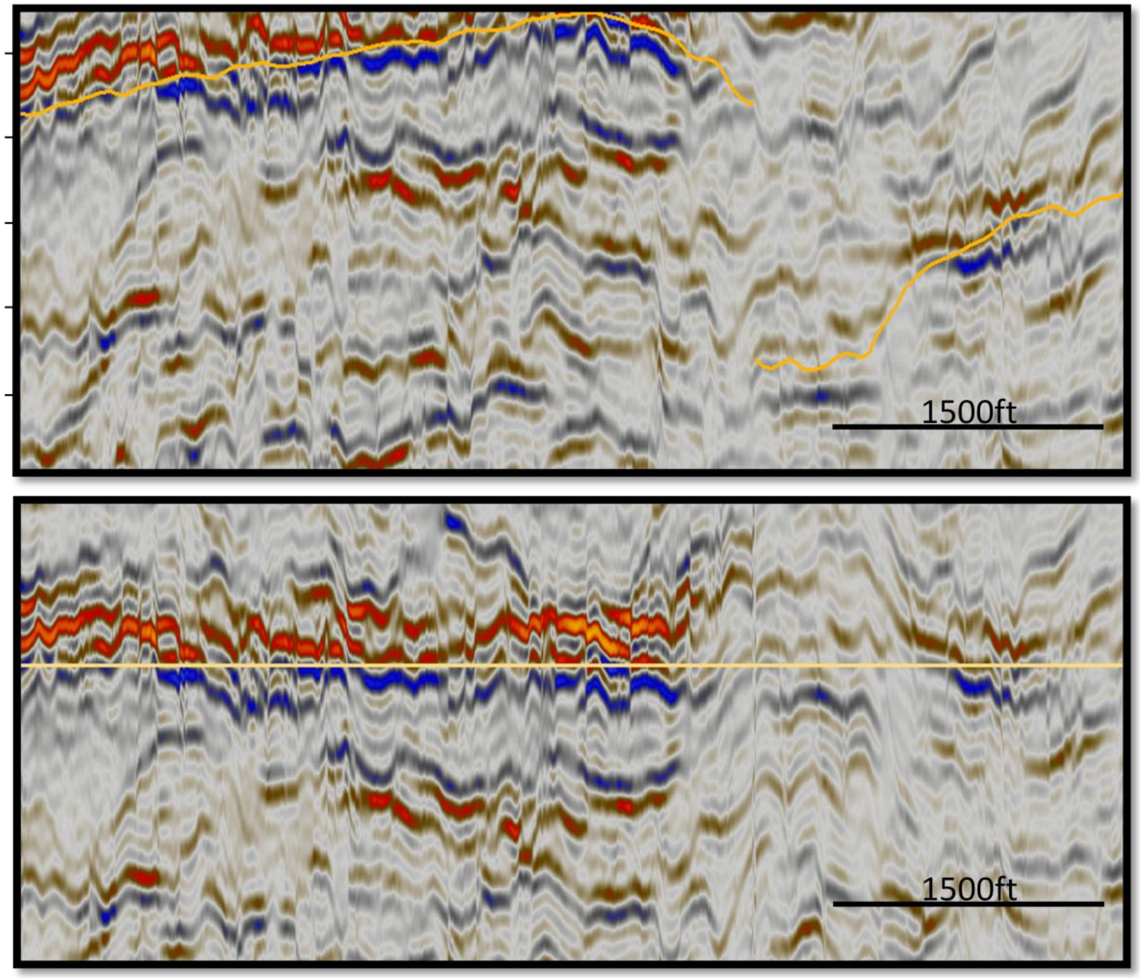


Fig 36: Upper Middle Wilcox flattened enhanced seismic interpretation. Comparing normal and flattened views of inline 1015 demonstrates that conventional seismic structure maps are valid for enhanced seismic. The southeastern fault is shown and was not active during deposition of the Upper Middle Wilcox. Onlap and downlap of the high amplitude seismic facies onto lower seismic facies is apparent.

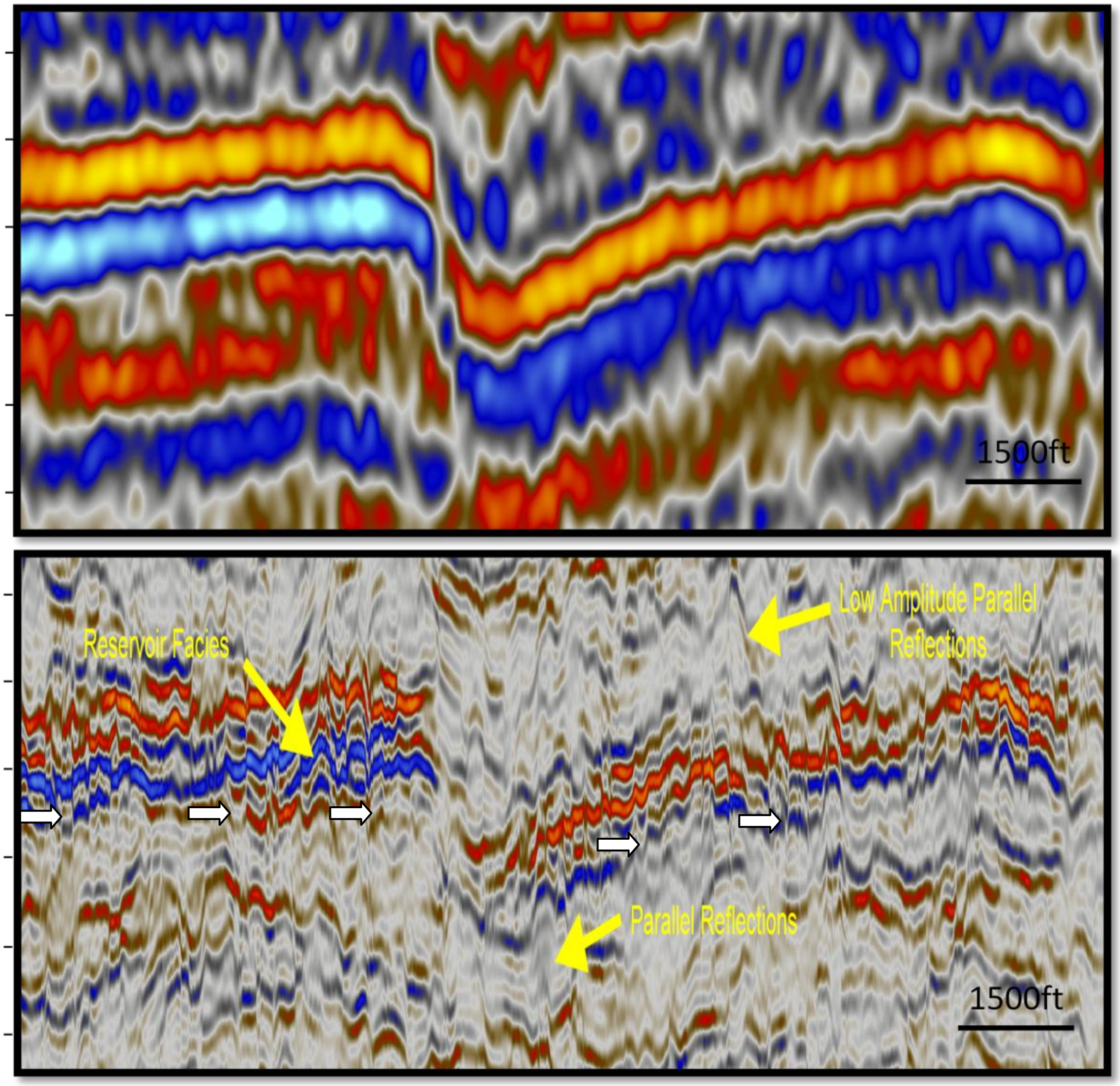


Fig 37: Upper Middle Wilcox enhanced seismic interpretation. Interpretation (bottom) centered on the middle fault showing reservoir seismic facies that both onlap and downlap underlying reflections. White arrows indicate onlap or downlap. The conventional seismic (above) is shown for comparison with the enhanced seismic (bottom).

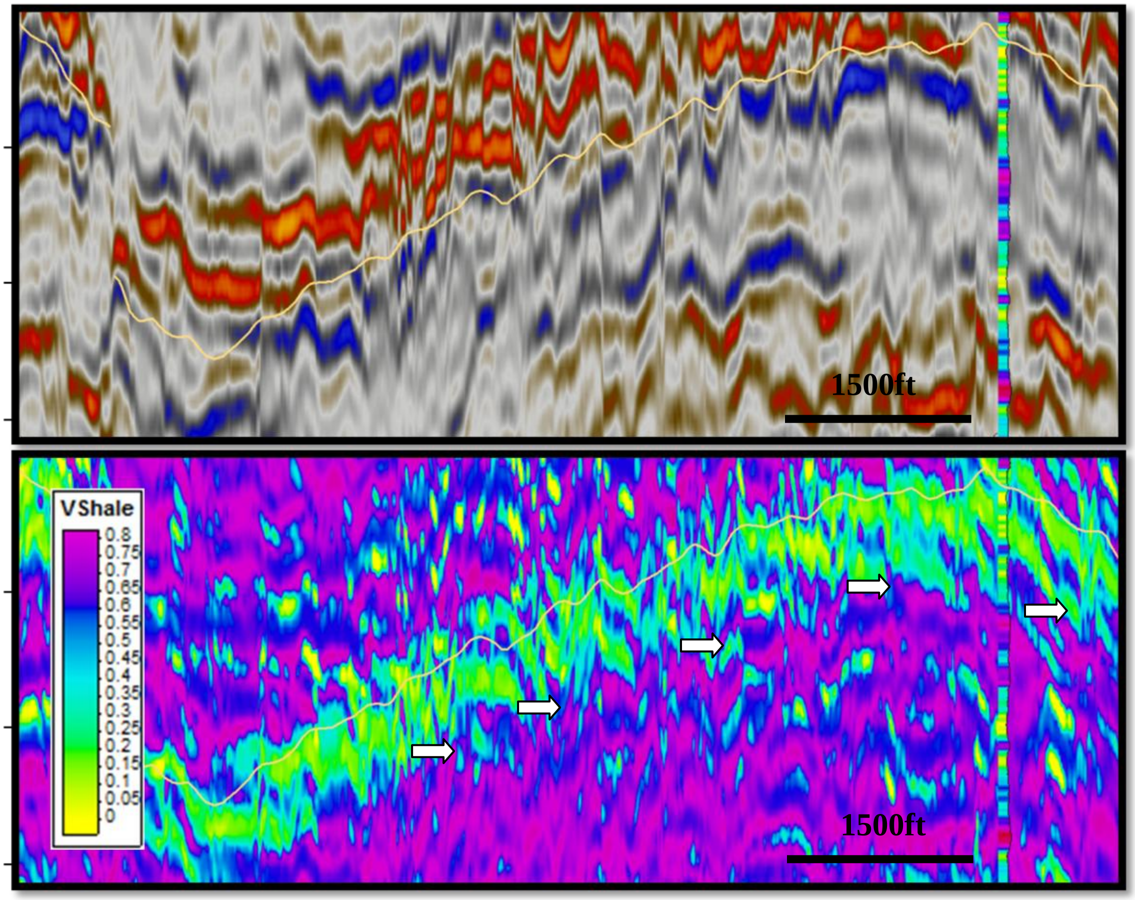


Fig 38: Upper Middle Wilcox comparison of enhanced seismic and enhanced shale content genetic inversion. From this one can see that better sands along the structure contour map correspond with sands that are more likely to be laterally connected. While arrows indicate downlap.

Reservoir Connectivity and Heterogeneity Analysis

Enhanced seismic interpretation of the Upper Middle Wilcox reservoir reveals a lobate progradational sand with stratigraphic variation and numerous secondary faults. These reservoir characteristics most likely do not hinder fluid flow. Petrophysical evaluation indicates that the clean sand is both porous and charged with hydrocarbons.

The overlaying shale seal and large-scale structural traps contain hydrocarbons within the reservoir.

Connectivity in the Upper Middle Wilcox is similar to the Upper Wilcox in that the shale content genetic inversion indicates a laterally extensive connected reservoir as shown in Figure 38. For this inversion the gamma ray logs from wells 2, 4, 8 and 11 were used to calculate shale percentage. Special care was made to match synthetic seismograms from each well with enhanced seismic traces. This permitted the clear identification of the reservoir as a progradational sand after the inversion. Extraction of sands from the genetic inversion onto the reservoir surface as shown in Figure 39 reveals lateral reservoir quality variation. Understanding variations in sand quality assists in the identification of well locations and planning of secondary recovery methods since reservoir flow characteristics can be determined with greater accuracy. Extraction from the enhanced seismic envelope volume along the reservoir structure map highlights areas that are structural highs and good reservoir sands (Figure 40). This indicates that high amplitudes in the enhanced seismic might be caused by fluid effects. Structural lows with good reservoir sand do not necessarily have high amplitudes. The contact between high and low amplitudes is probably a water contact.

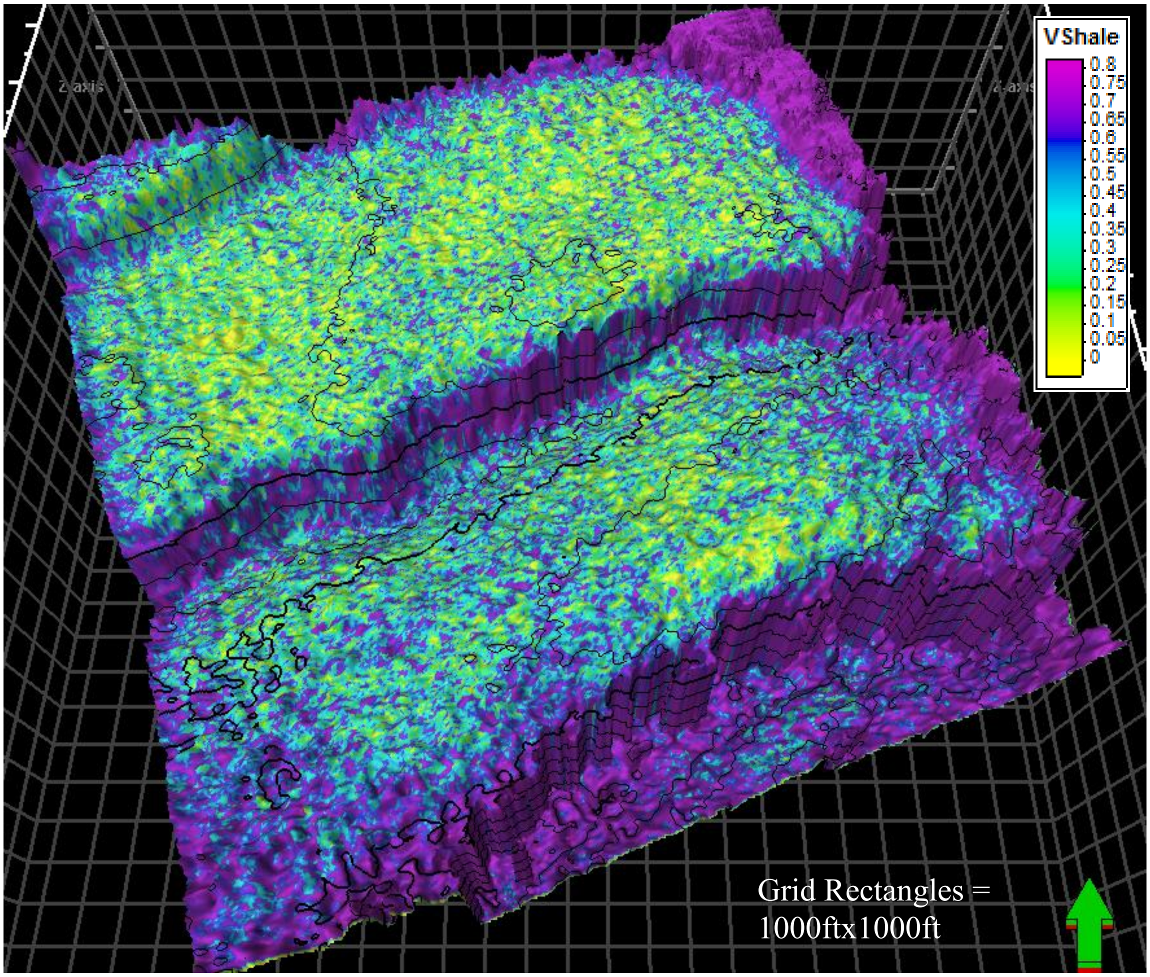


Fig 39: Shale content extraction along the Upper Middle Wilcox reservoir interval. Brighter green and yellow regions contain higher quality sands while blue and purple regions represent shale. Sands were deposited preferentially on the peaks of the anticlines and landward of the central fault.

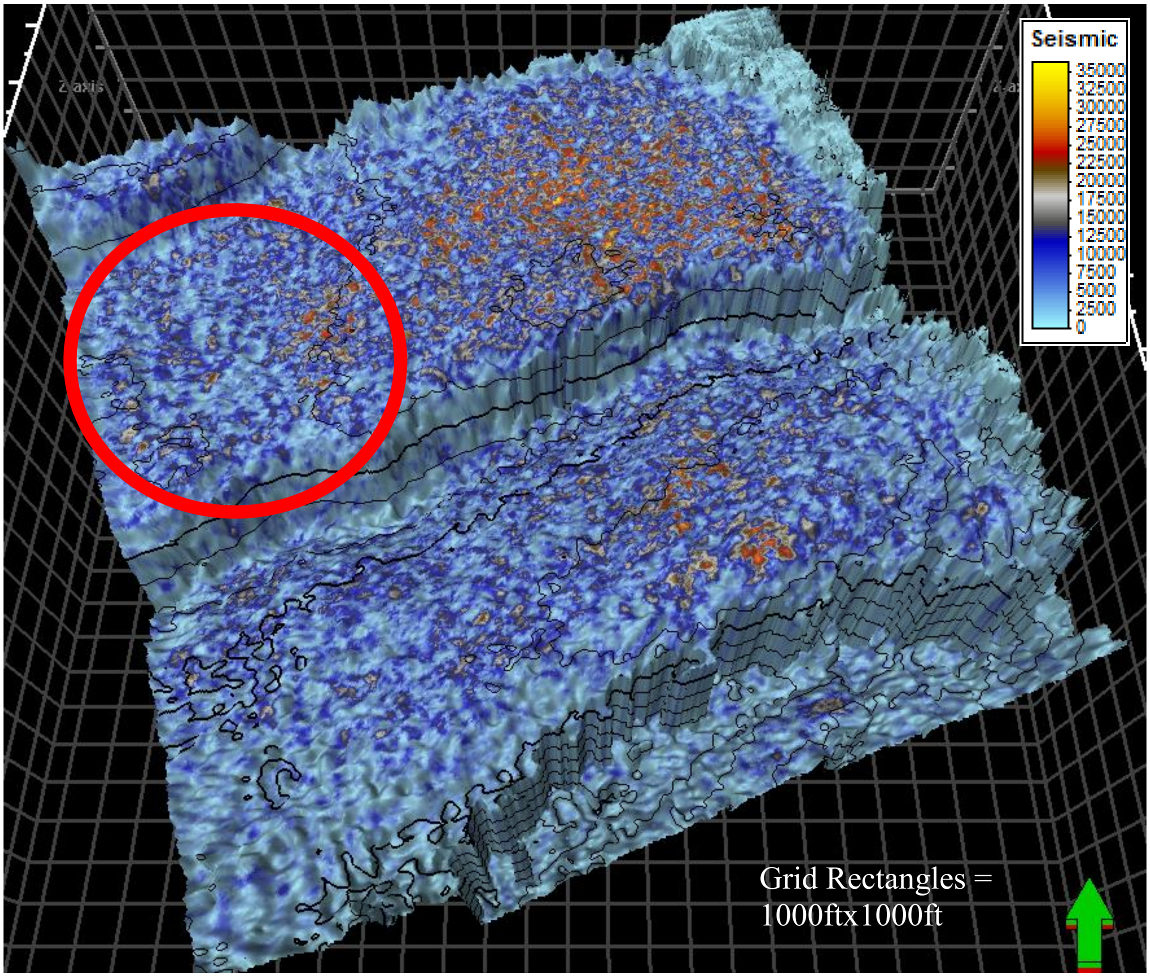


Fig 40: Upper Middle Wilcox surface extraction of the enhanced envelope attribute. High amplitudes correlate with better reservoir sands. The circled region represents a structural low where quality sands did not correspond with high amplitudes. This is indicative of a water contact and suggests that fluid content affects amplitude.

Conclusion

This Upper Middle Wilcox reservoir heterogeneity study utilized a shale content genetic inversion along with structural and stratigraphic analysis to identify lateral and vertical variations in reservoir properties. These property variations were dependent on the stratigraphic and depositional characteristics as imaged with enhanced seismic facies. The Upper Middle Wilcox reservoir depositional setting might have been associated with gravity flows caused by slumping and instability after fault movement. If this is the case then these sands moved along depositional strike towards submarine canyons and deep water.

CHAPTER VII

MIDDLE WILCOX RESERVOIR HETEROGENEITY MODEL

Introduction

Well 4 produces from Middle Wilcox reservoir sands between 12296ft and 12418ft subsea depth. Cumulative production between 1991 and 2009 was 3.32 billion cubic feet of gas and 218,259 barrels of liquid hydrocarbons. Reservoir heterogeneity and connectivity analysis of the Middle Wilcox reservoir interval intends to delineate of connected reservoir volumes around Well 4 and estimate the possible drainage area accessible to this well. Focus is placed on delineating any barriers that might isolate reservoir bodies, calculating in-place resources, and solidifying the proposed methodology for finding bypassed hydrocarbons.

Well Log Analysis

Figure 41 illustrates the petrophysical analysis results for the Middle Wilcox including shale content, water saturation, and porosity in Well 4. Net pay was set at shale percentages less than 60%, water saturations less than 50%, and porosities greater than 10%. Well logs indicate that the reservoir consists of two stacked clean sands with significant quantities of hydrocarbons and porosities around 15%. Reservoir sands coarsen upwards suggesting deposition as two distinct packages separated by a flooding surface.

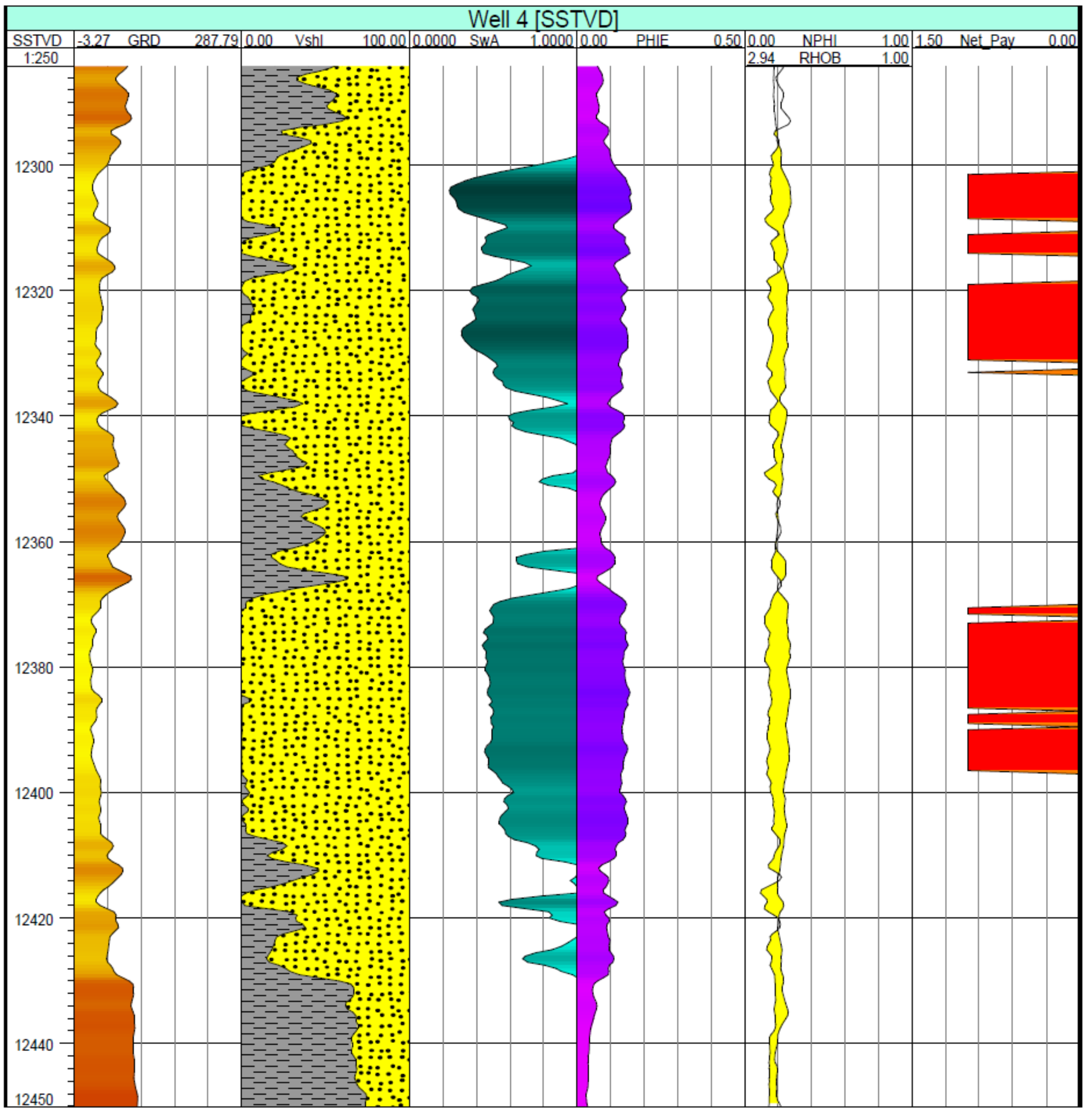


Fig 41: Formation evaluation of the Middle Wilcox reservoir interval. Logs displayed from left to right are gamma ray, shale percent, water saturation, porosity, neutron density porosity crossover, and net pay.

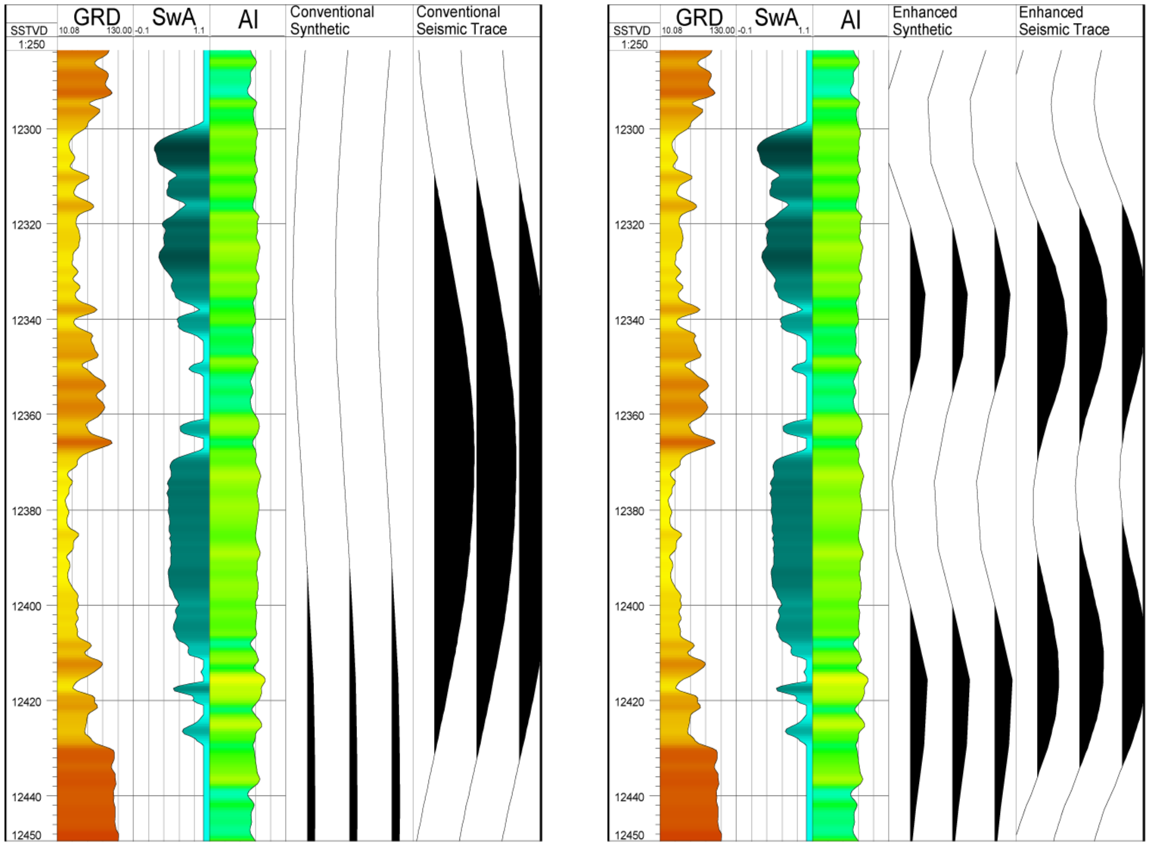


Fig 42: Conventional (left) and enhanced (right) synthetic seismograms in the Middle Wilcox reservoir interval. Tracks shown contain gamma ray, water saturation, acoustic impedance synthetic seismograms, and extracted seismic traces in that order.

Synthetic Seismogram Analysis

The conventional synthetic seismogram and extracted seismic traces for Well 4 in the Middle Wilcox are shown in Figure 42 on the left side. Potentially productive intervals can be identified in the conventional seismic as peaks, but poor seismic resolution prohibits the identification of individual reservoir sands. This is due to the low dominate frequency of the conventional seismic with wavelengths of about 690ft.

The smallest bed thickness where both the top and base can be identified is about 173ft. The smallest visible bed would be approximately 87ft. Thus individual reservoir sands in the Middle Wilcox cannot be delineated with conventional seismic.

The Middle Wilcox enhanced synthetic seismogram and extracted traces located on the right side in Figure 42 clearly correlate with individual reservoir sands. The productive interval from 12250ft to 12450ft contains reservoir sands that are identifiable in enhanced seismic as high amplitude troughs. The dominate frequency for the Middle Wilcox enhanced seismic is 65Hz with a wavelength of around 175ft, separable resolutions at 45ft, and visible resolutions at 23ft. Since gas bearing sands tend to have large influences on amplitude in enhanced seismic, even thin reservoir sands are identifiable.

Conventional Seismic Analysis

The structural complexity of the Middle Wilcox reservoir is significantly greater than that of the previous two studied reservoirs. Conventional seismic interpretation and coherency volume analysis identified several large-scale faults. The northwestern fault appears to consist of a single fault that trends to the northeast and only intersects a corner of the seismic survey. The central large-scale faults parallel each other and trend northeast dividing the seismic dataset in half. The southeastern most large-scale fault intersects the other two reservoir intervals and appears to not have any large secondary faults. Based on the structure map shown in Figure 43 and the coherency time slice shown in Figure 44 all faults visible on conventional seismic detrimentally influence fluid flow. The anticlines created by these normal faults form the primary trapping mechanism for hydrocarbons.

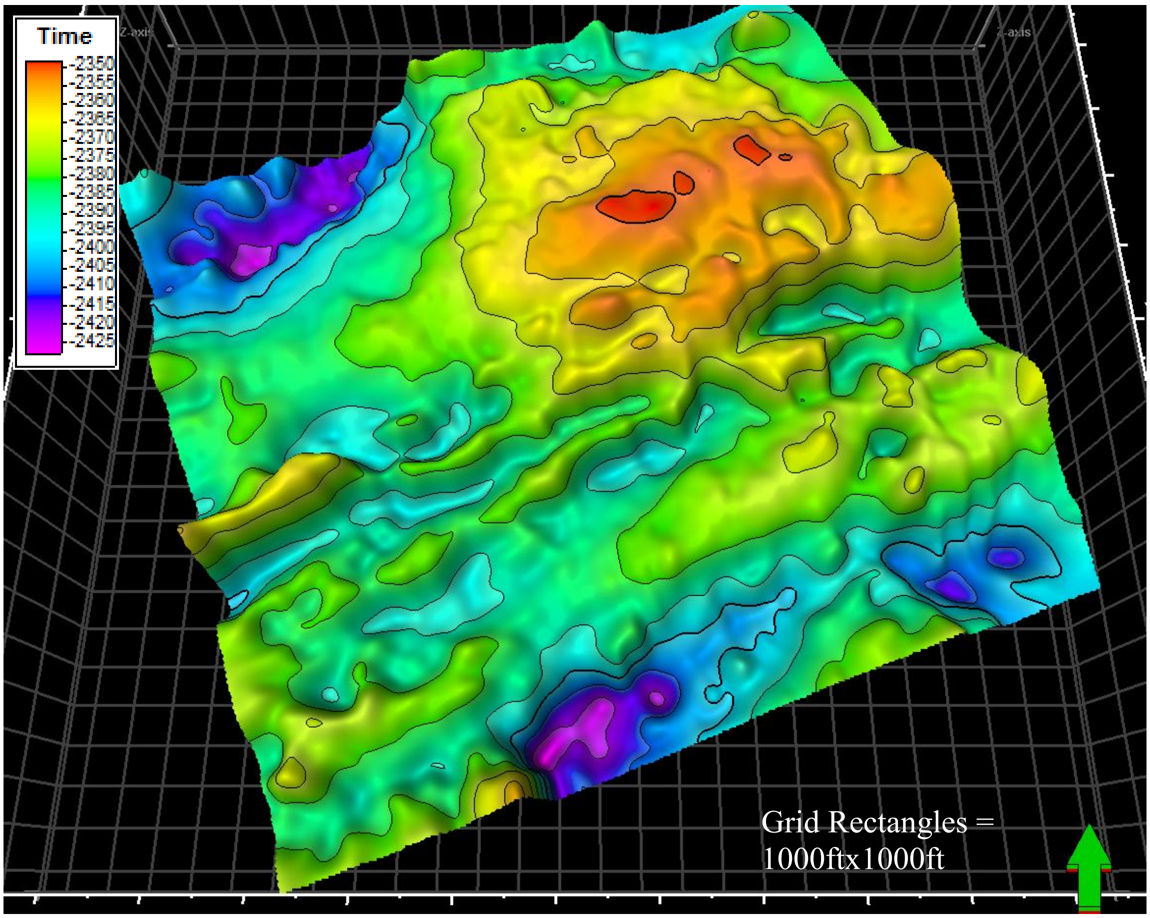


Fig 43: Conventional seismic Middle Wilcox reservoir structure map.

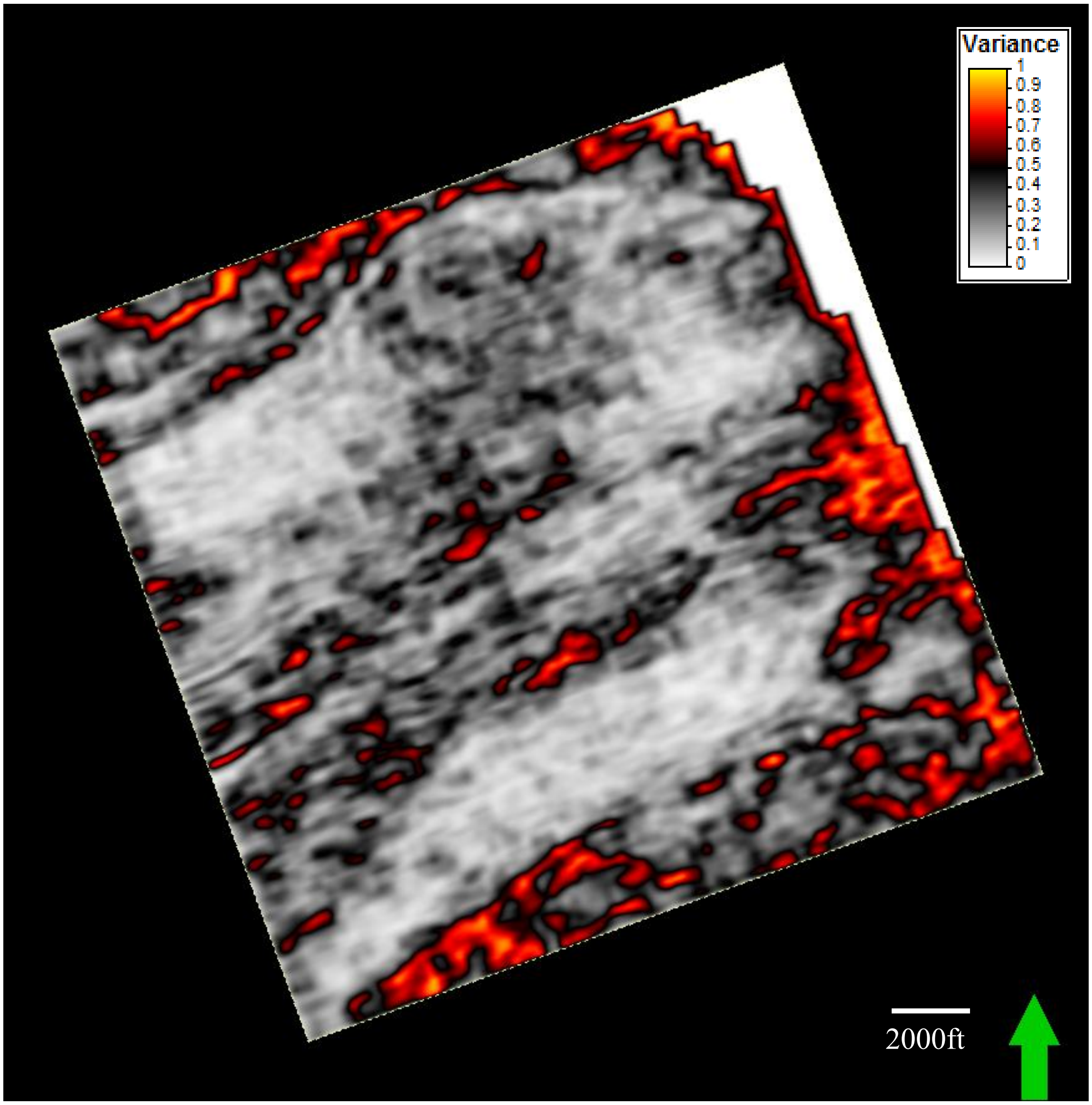


Fig 44: Conventional seismic coherency attribute time slice at 2400ms. Large faults to the northwest and southeast are visible. The central faults are less continuous and have smaller offsets.

Enhanced Seismic Analysis

There are several structural features present in the enhanced seismic affecting the reservoir that are not apparent in conventional seismic. In addition to the large-scale faults identifiable with conventional seismic, enhanced seismic reveals numerous secondary faults that also intersect the reservoir. These secondary faults are both antithetic and synthetic to the main faults and are associated with deformation and folding of the Wilcox. When these faults are compared to the reservoir thickness one cannot easily determine if secondary faulting detrimentally influences fluid flow.

Seismic facies analysis of this reservoir reveals that it is bound at the top and bottom by progradational clinoforms. These clinoforms are most likely associated with deltaic deposition. The Middle Wilcox reservoir sands were deposited during a transgression. Figure 45 shows the reservoir interval and related deltaic seismic facies. There are significant variations laterally within this reservoir sand due to both stratigraphic and structural features. These geologic features in enhanced seismic do not conclusively demonstrate the presence or absence of flow barriers.

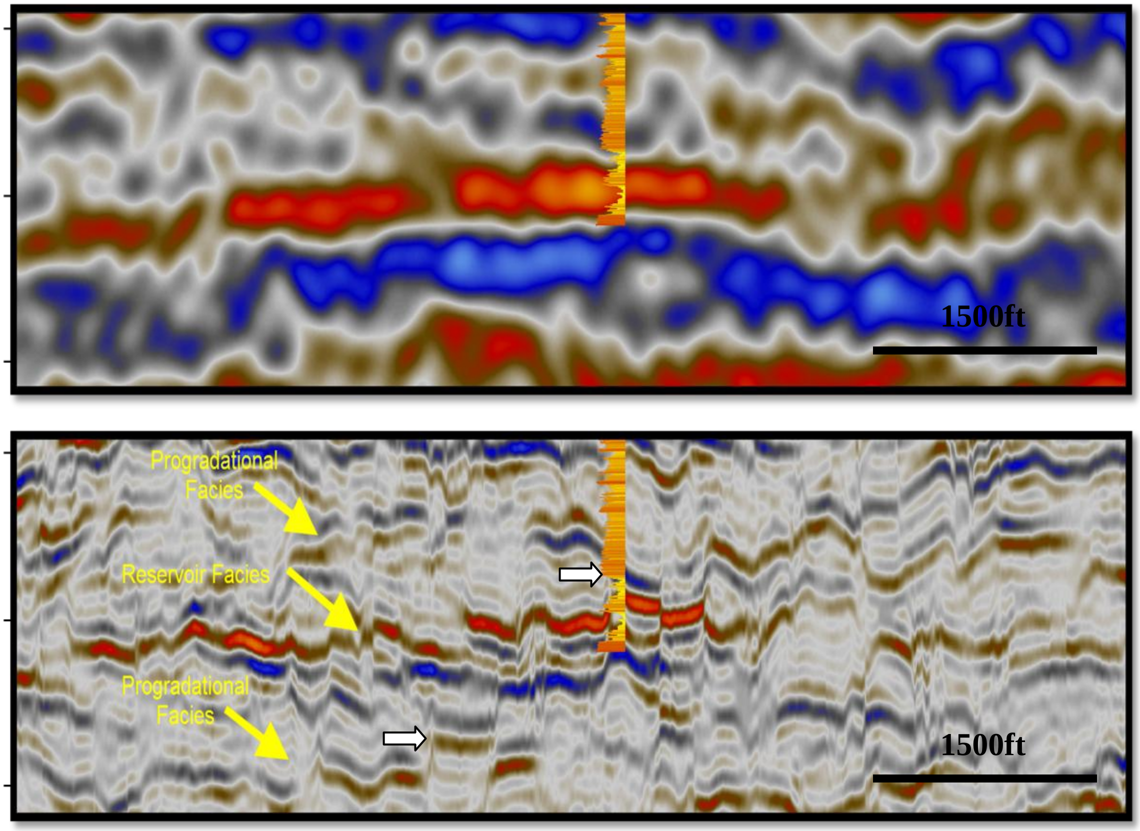


Fig 45: Enhanced seismic interpretation showing Middle Wilcox reservoir interval. The reservoir is a transgressive sand between two progradational deltaic seismic facies. White arrows indicate downlap.

Reservoir Connectivity and Heterogeneity Analysis

Production in Well 4 is from a faulted sheet sand deposited between two progradational seismic facies. Hydrocarbon flow may be inhibited by stratigraphic or structural traps. These traps can be identified with connectivity analysis and seismic interpretation.

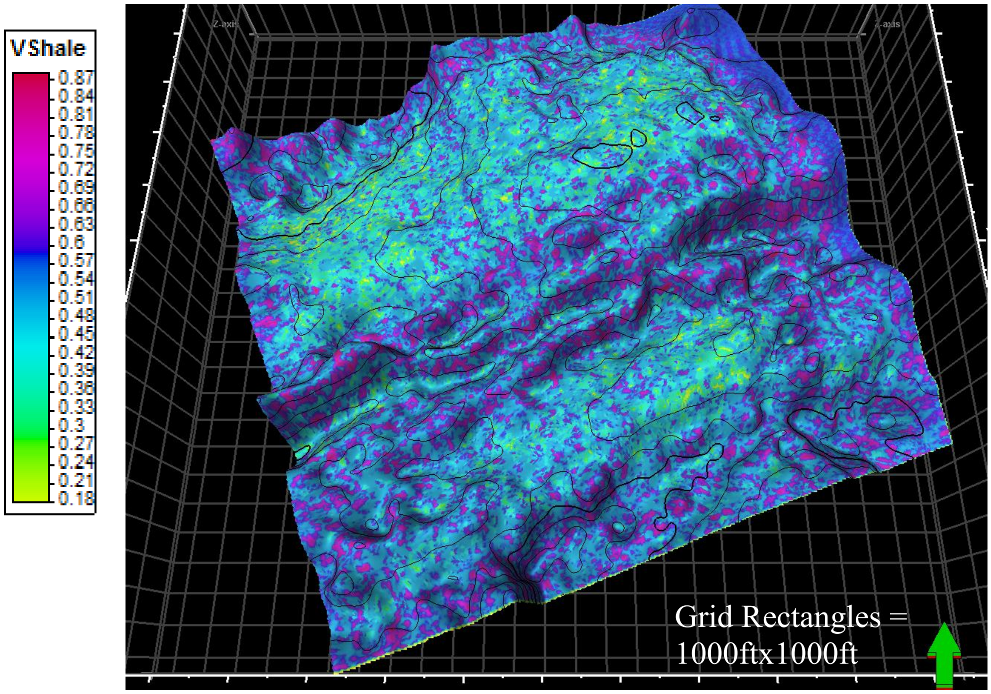


Fig 46: Shale content extraction along the Middle Wilcox reservoir interval. High reservoir quality occurs in regions with yellow and green.

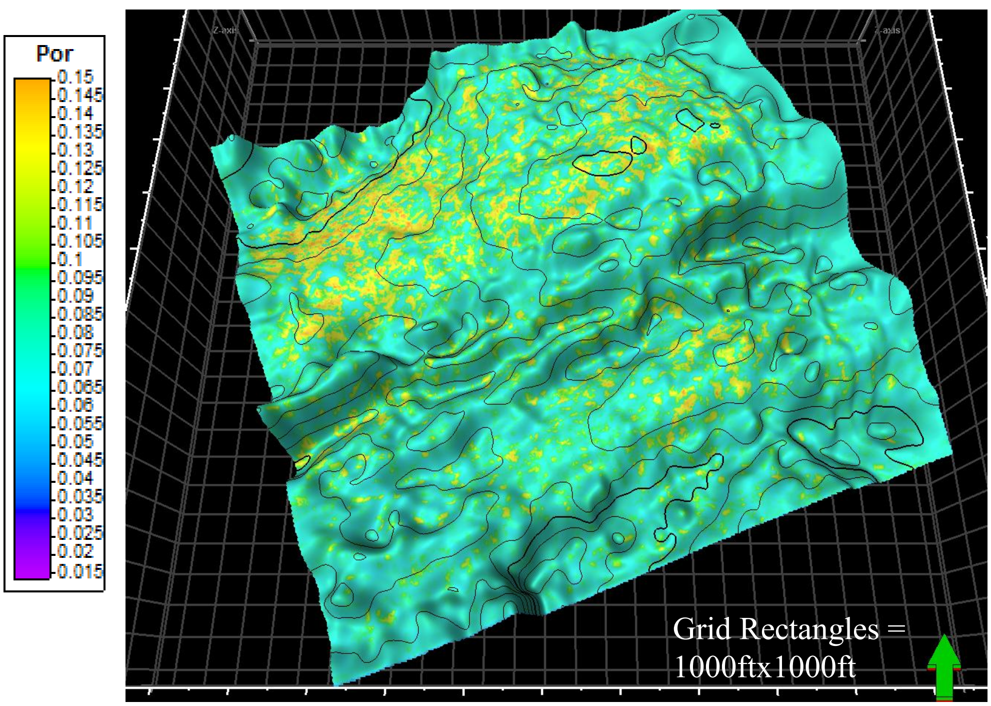


Fig 47: Porosity extraction along the Middle Wilcox reservoir interval. Notice that sands have porosities around 15% while shale has porosity around 6%.

Reservoir connectivity analysis for Well 4 consisted of identifying regions with sand, porosity, connectivity, and high seismic amplitudes. Once potential reservoir compartments were identified extracted geobodies based on shale content of 35%, 40%, and high amplitudes were used for flow unit delineation and volumetric calculations. Figure 46 illustrates a Middle Wilcox surface extraction of the shale content genetic inversion and allows for the identification of potential reservoir sand bodies. Porosity and connectivity are shown in Figures 47 and 48, respectively. Since shales have porosity but not permeability, a connectivity proxy was used to delineate probable reservoir intervals. The envelope surface extraction, Figure 49, indicates the presence of hydrocarbons at the time of seismic acquisition. Geobodies were extracted only for reservoir bodies that contained porous permeable sands with hydrocarbon indications. Comparison of these geobodies with each other confirms that bright spots are associated with high reservoir quality. Determining reasonable sand percentages for delineation of flow units can be achieved by comparing in-place hydrocarbon volumes with production information. The reliability and usefulness of the interpretation methodology developed in this study can be confirmed through reservoir connectivity analysis for Well 4.

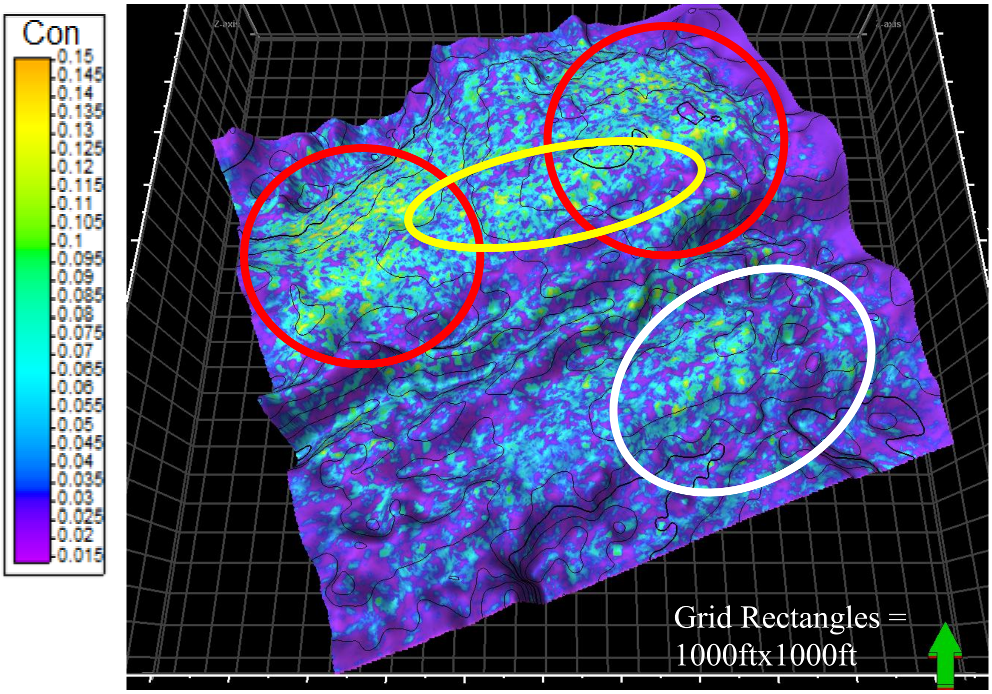


Fig 48: Connectivity extraction for the Middle Wilcox reservoir interval. Reservoir flow units indicated by red circles. Yellow indicates a possible connection between flow units. White indicates a sand with insufficient porosity and connectivity.

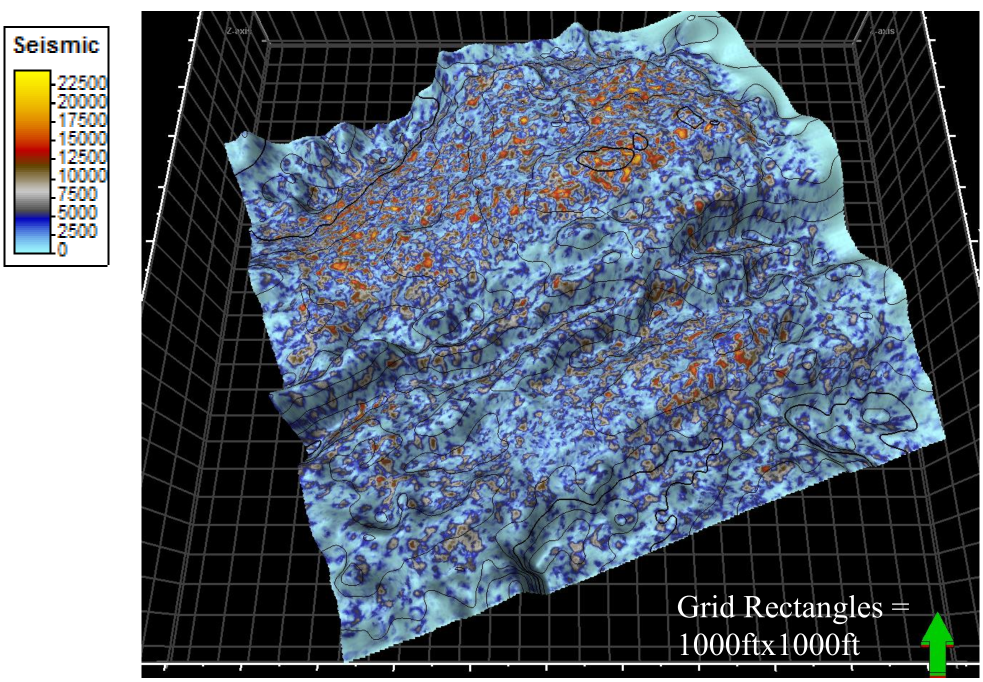


Fig 49: Middle Wilcox surface extraction of the enhanced envelope attribute. High amplitude regions match regions with high reservoir quality.

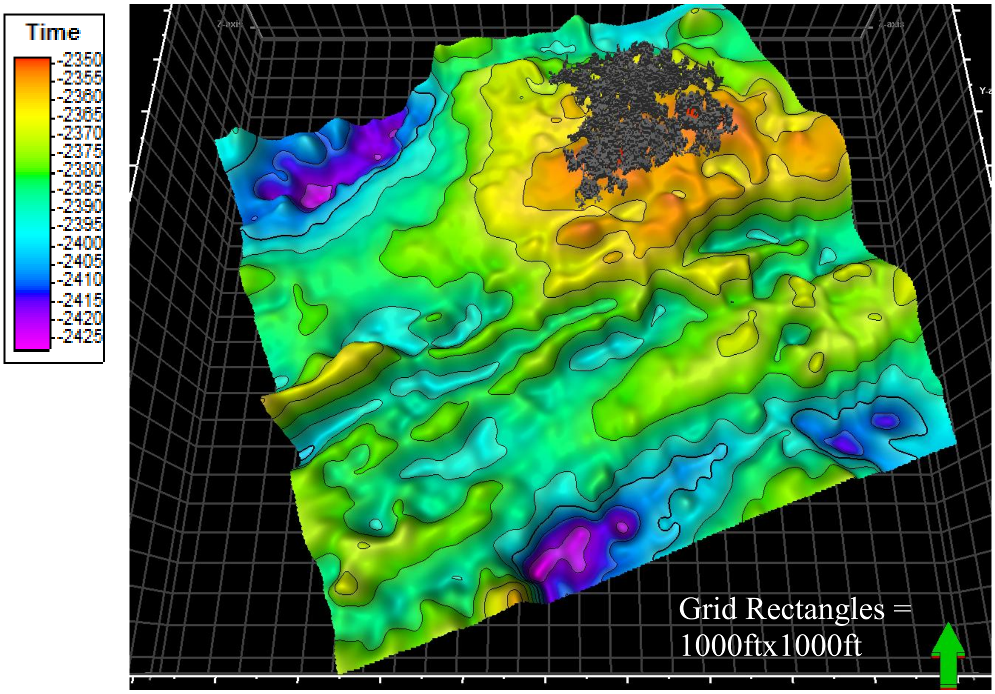


Fig 50: Middle Wilcox reservoir geobody representing connected sands with 35% shale content near Well 4.

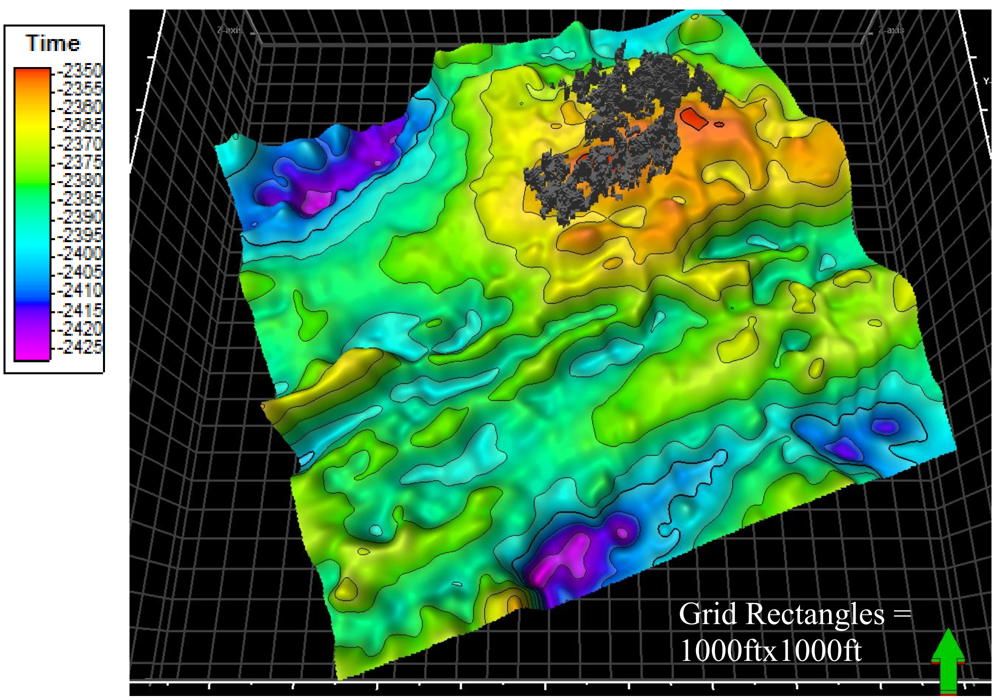


Fig 51: Middle Wilcox reservoir geobody representing connected high-amplitude regions near Well 4.

Comparison of the 35% shale geobody, Figure 50, and the high amplitude geobody, Figure 51, intersecting the producing interval of Well 4 revealed remarkable similarities. These similarities indicate that fluid effects cause high amplitudes in charged sands that have 35% or less shale content. Such an observation might permit the determination of similar sands elsewhere within the enhanced seismic survey.

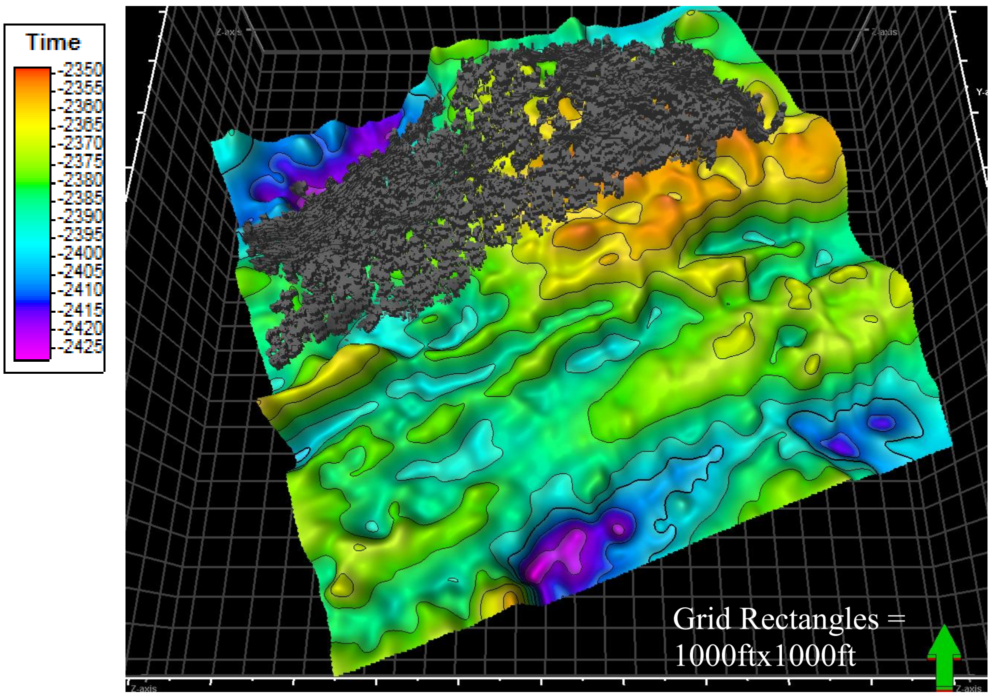


Fig 52: Middle Wilcox reservoir geobody representing connected sands with 40% shale content near Well 4.

Calculation of rock and in-place hydrocarbon volumes for reservoir bodies extracted at Well 4 with shale content cutoff values of 35% and 40% reveal that Well 4 production comes from a geobody connecting sands with 40% or less shale, Figure 52. The geobody connecting sands with only 35% shale contains approximately 8.01 billion cubic feet of rock while the 40% shale geobody contains 41.53 billion cubic feet of rock. The 35% shale geobody is restricted and confined by stratigraphic influences, secondary faults, and large-scale faults that segment high quality reservoir sands. The 40% shale geobody is laterally extensive and confined only by large-scale faults without any indications of stratigraphic trapping. The 35% shale geobody rock volume seems unreasonably low considering that production from Well 4 is greater than 3.3 billion cubic feet of natural gas. The larger 40% shale geobody is more plausible and most likely represents producing connected reservoir sands. Original gas in place was calculated using an average water saturation of 54.8% and an average porosity of 14%. With these parameters, sands with 35% shale hold 0.5 billion cubic feet of hydrocarbons under reservoir conditions while sands with 40% shale hold 2.63 billion cubic feet of hydrocarbons under reservoir conditions. Improved determination of water saturation and porosity might permit a more accurate calculation of gas in-place. The 40% shale reservoir body is limited by the extent of the seismic survey and excludes hydrocarbons that migrate towards the well from regions without seismic data. Any hydrocarbons that migrate along faults from other reservoir sands are also excluded from this calculation.

Once a reasonable cutoff value has been determined for potentially productive sands that permit fluid flow, one can search for sand bodies containing bypassed hydrocarbons. If, in the Middle Wilcox, greater than 35% shale prohibited fluid flow then Well 4 would have been producing from the northeastern corner of the survey while another viable productive sand would have been left unproduced in the northwestern corner of the survey, Figure 53. This northwestern flow unit would have a stratigraphic trap preventing lateral migration of hydrocarbons and might be a viable target for future exploration. Even if both high quality reservoir sands are connected production from

Well 4 might not adequately drain the sands in the northwestern corner of the study area. Further reservoir engineering and simulation analysis is required to evaluate the economic potential of this example; however, the concept and methodology provide a means to delineate potentially productive bypassed hydrocarbons.

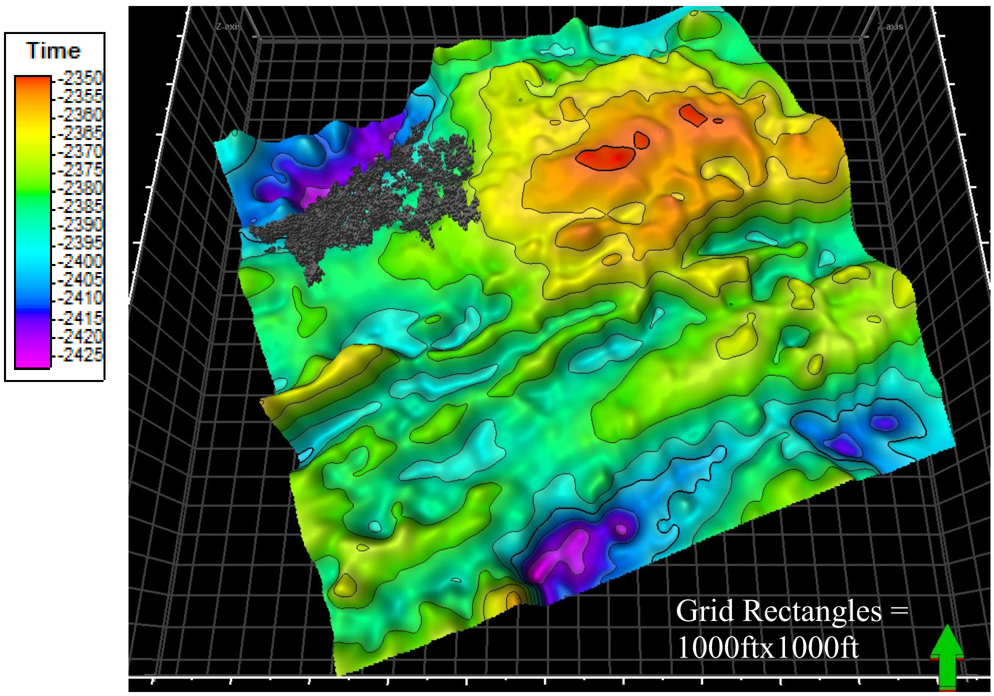


Fig 53: Middle Wilcox reservoir geobody representing connected sands with 35% shale content in the structural low away from Well 4.

Conclusion

Enhanced seismic interpretation in conjunction with reservoir connectivity and heterogeneity analysis can provide more accurate delineation of connected reservoir bodies, determination of hydrocarbon volumes, and identification of bypassed flow units. Heterogeneities identified in the Middle Wilcox reservoir included antithetic and synthetic secondary faults associated with Wilcox deformation as well as seismic facies that suggest the reservoir is a transgressive sand positioned between two progradational packages.

Connectivity analysis on the Middle Wilcox explored techniques associated with identifying both tapped and untapped flow units. Geobodies extracted from shale content genetic inversion volumes were used for hydrocarbon volume calculations with results compared to actual production. A methodology was also proposed for the identification of bypassed hydrocarbons in untapped flow units. This methodology followed a net pay approach where sands, porosity, permeability, and hydrocarbons all had to be present. From these analyses the Middle Wilcox reservoir interval demonstrates potential value that can be derived from reservoir connectivity and heterogeneity analysis and enhanced seismic interpretation.

CHAPTER VIII

CONCLUSIONS

Enhanced seismic interpretation integrated with outcrop analysis, well data, and conventional seismic interpretation enables a more accurate and comprehensive characterization of reservoir heterogeneity, connectivity, and flow units. Analysis in this study of a mature producing field from the Wilcox Group using enhanced seismic provided geologic insight into depositional facies, structure, and connected reservoir flow units that were not previously available. Improved geologic understanding of reservoir characteristics could reduce economic and geologic risk permitting more reliable redevelopment of this and other mature fields.

The methodology developed in this study involves numerous steps including interpretation of analog data, well logs, conventional seismic, and enhanced seismic. These steps as outlined in Figure 54 all contribute to generating a reservoir heterogeneity and connectivity model. This model contains the results of enhanced seismic connectivity and heterogeneity analysis as well as large-scale structures from conventional seismic and reservoir properties from petrophysical analysis. By creating reservoir heterogeneity and connectivity models for three reservoir intervals this study demonstrates the usefulness of this methodology.

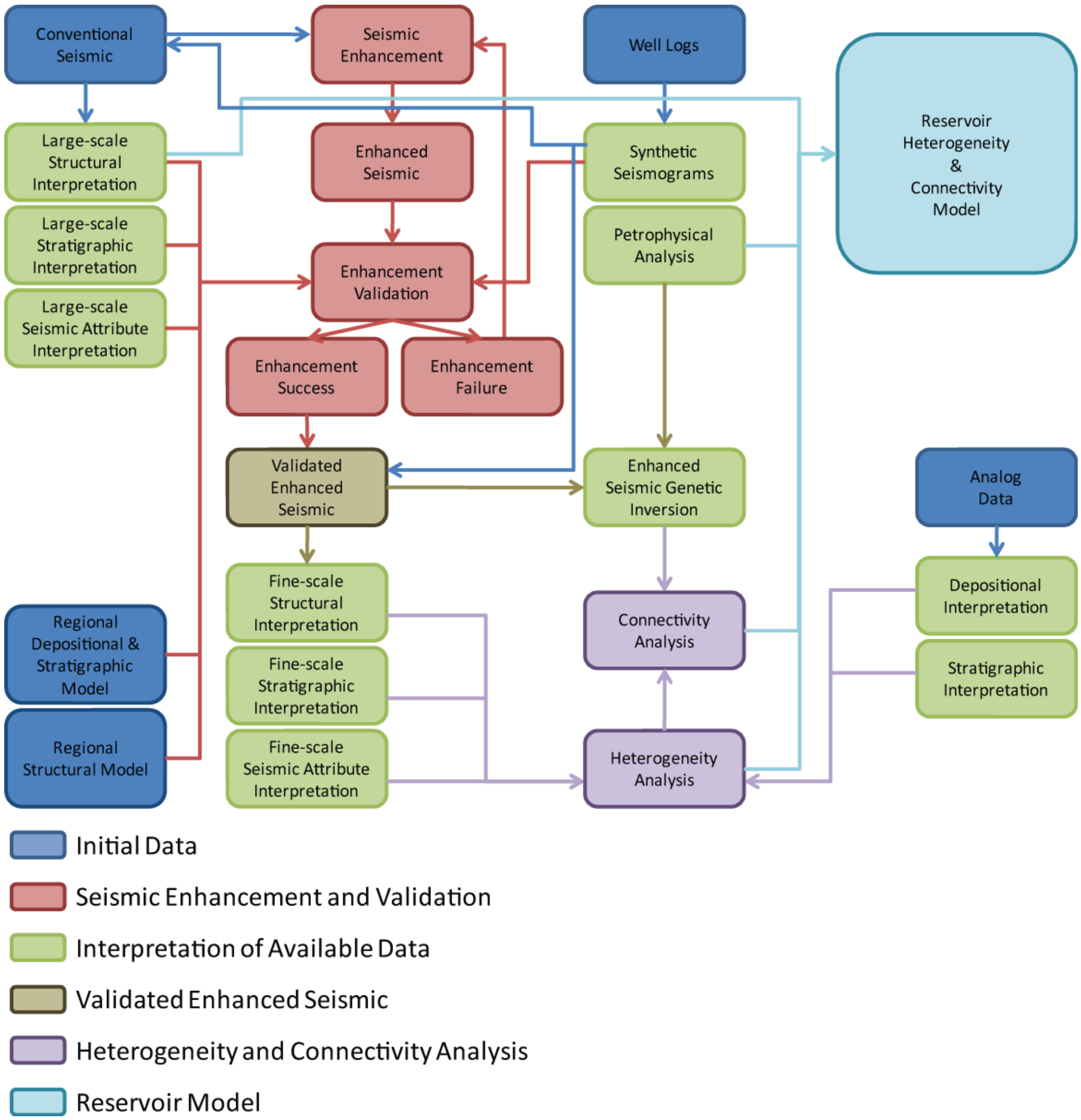


Fig 54: Flow chart of enhanced seismic interpretation methodology for reservoir heterogeneity and connectivity characterization.

Examples included a clear demonstration of improved geologic consistency for enhanced seismic over conventional seismic in the Upper Wilcox reservoir interval. Specifically, comparative interpretation of this interval with both enhanced and conventional seismic showed that unlike conventional seismic enhanced seismic could reveal connected thin reservoir sands and indicate that large faults acting as barriers could trap hydrocarbons from the drainage of adjacent production wells. Knowledge of these characteristics reduces geologic risk and encourages further development of mature fields.

The Upper Middle Wilcox interval demonstrated the ability of reservoir heterogeneity and connectivity analysis for identification of depositional facies, reservoir property variations, and reservoir quality. This included mapping lobate sands that are most likely associated with fault related gravity flows. Applications for this methodology pertain to selecting infill and injection well locations that maximize the ultimate recovery of hydrocarbons from a reservoir.

Detailed enhanced seismic heterogeneity and connectivity analysis in conjunction with production comparisons in the Middle Wilcox assisted in the delineation of reservoir characteristics and flow units making the detection of bypassed hydrocarbons possible. This included the use of genetic inversion enhanced seismic volumes for delineation of charged flow units by identifying areas with sand, porosity, connectivity, and hydrocarbon indications. Different parameters for delineation of reservoir bodies could mean large differences in reservoir compartment volumes and potentially the connection or separation of flow units. This could be addressed in future studies by comparing the reservoir heterogeneity and connectivity model with reservoir simulations and production information.

These analysis demonstrate that enhanced seismic provides significant insight into reservoir heterogeneities and connectivity by imaging geologic features which were not previously detectable. The enhancement significantly broadens frequency bandwidth while maintaining a high signal-to-noise ratio. The dominant frequency of the conventional seismic data used, in this study, was 16 Hz with resolvable beds of greater than 175 ft. Faults with offsets as low as 80 ft were visible. The enhanced seismic has a dominate frequency of 65 Hz with resolvable beds of 45 ft. Fault offsets in the enhanced seismic were as low as 20ft.

Application of enhanced seismic interpretation methods developed in this study still need to be tested in different structural and depositional regimes and situations. For instance, enhanced seismic interpretation could benefit unconventional and carbonate reservoir development, as well as exploration in frontier regions. Continued development of the interpretation methodology should focus on computerized statistical interpretation techniques like seismic inversion since the amount of data in enhanced seismic can be overwhelming.

Through the use of three intervals in a structurally complex Wilcox Group onshore Gulf Coast Basin mature field, this study demonstrated that enhanced seismic can significantly improve imaging resolutions and the ability to model reservoir heterogeneity and connectivity. This methodology can assist in maximizing recovery factors by reducing risks at relatively low costs permitting significant production increases from mature fields.

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